

United States
Environmental Protection
Agency

Office of Solid Waste
and Emergency Response
Washington, DC 20460

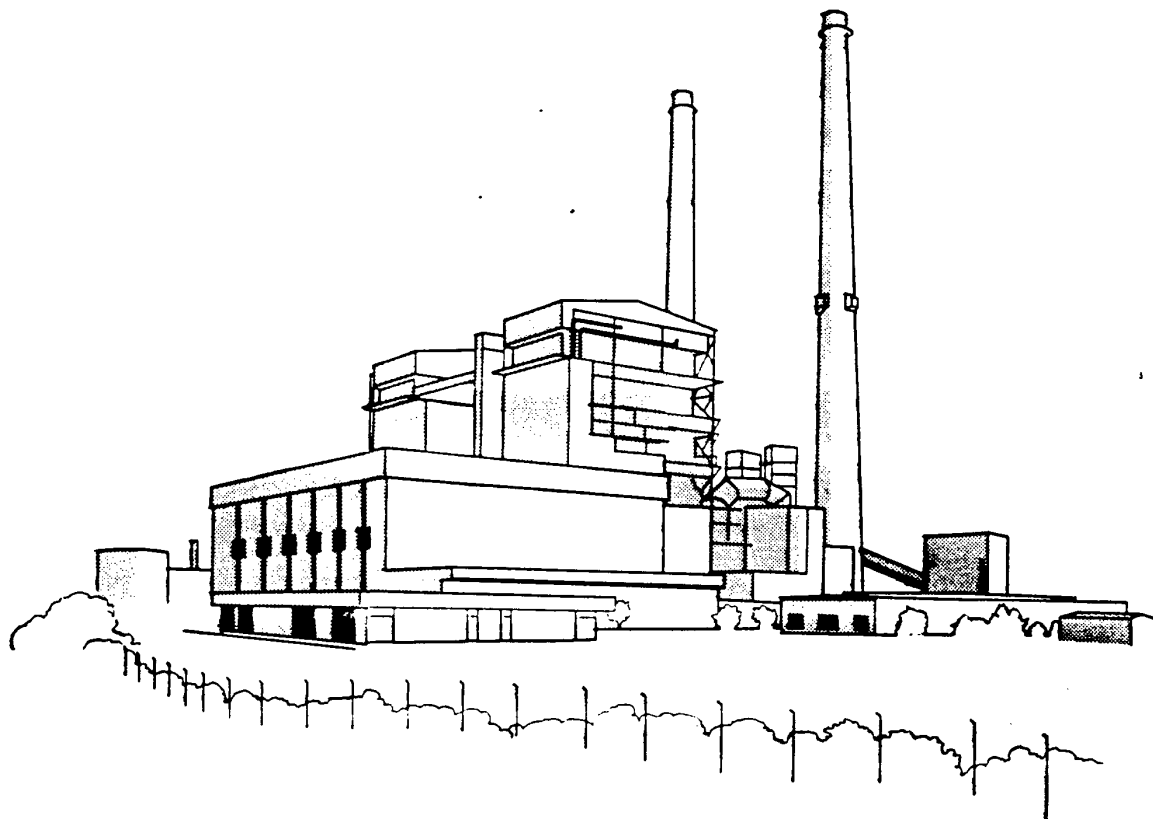
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February 1988

Solid Waste



Report to Congress

Wastes from the Combustion of Coal by Electric Utility Power Plants





UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable George Bush
President of the Senate
Washington, D.C. 20510

Dear Mr. President:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

A handwritten signature in black ink, appearing to read "Lee M. Thomas".

Lee M. Thomas

Enclosure



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable James C. Wright
Speaker of the House
of Representatives
Washington, D.C. 20515

Dear Mr. Speaker:

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Sincerely,

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Lee M. Thomas

Enclosure

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EXECUTIVE SUMMARY

The Environmental Protection Agency (EPA) has prepared this report on fossil fuel combustion wastes pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), as amended in 1980. These amendments to the Act added Section 8002(n), which directed the Administrator of EPA to

conduct a detailed and comprehensive study and submit a report on the adverse effects on human health and the environment, if any, of the disposal and utilization of fly ash waste, bottom ash waste, slag waste, flue gas emission control waste, and other by-product materials generated primarily from the combustion of coal or other fossil fuels.

Pending the completion of this study, fossil fuel combustion wastes were exempted from the hazardous waste requirements established under RCRA. Under Section 3001(b)(3)(A), EPA is prohibited from regulating these wastes until at least six months after this report is submitted to Congress.

If EPA determines that fossil fuel combustion wastes are hazardous under RCRA, and therefore subject to regulation under Subtitle C, EPA has some flexibility to promulgate regulations that take into account the unique characteristics of these wastes. Section 3004(x) states ...

If ... fly ash waste, bottom ash waste, slag waste and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels ... is subject to regulation under this subtitle, the Administrator is authorized to modify the requirements of subsections (c), (d), (e), (f), (g), (o) and (u) and section 3005(j) ... to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment.

ES-2

This report examines only those wastes generated from the combustion of coal by the electric utility industry. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. EPA has deferred study of the disposal of wastes generated by the combustion of other fossil fuels and from coal combustion in industries other than the electric utility industry until a later date.

Coal-fired power plants produce substantial quantities of wastes. In 1984 about 69 million tons of ash and 16 million tons of flue gas desulfurization wastes were generated. Because of increasing reliance on coal for producing electricity, by the year 2000 the amount of ash waste is expected to increase by about 75 percent to about 120 million tons annually; production of FGD wastes is expected to triple to about 50 million tons annually.¹ In addition to the high-volume ash and flue gas desulfurization wastes, coal-fired power plants also generate several lower-volume waste streams as a result of equipment maintenance and cleaning activities.

About one-fifth of all waste generated at coal-fired electric utility power plants is currently reused; the remaining four-fifths are typically disposed in surface impoundments or landfills. The recycled wastes, usually fly ash, bottom ash, or boiler slag, have been used primarily as cement additives, high-volume road construction material, and blasting grit. There is some potential for increased use of these wastes in such applications. However, barring the

¹ It is possible that advances in coal combustion technology will alter the amount and types of coal-combustion wastes produced in the future. An analysis of these technological advances is beyond the scope of this report.

ES-3

development of new utilization techniques, or major changes in combustion and environmental control technologies, the proportion of coal combustion wastes that are reused is unlikely to change significantly.

While utility waste management sites are currently exempt from RCRA hazardous waste requirements, they are subject to state and local level solid waste laws and regulations. There is substantial variation in the state-mandated disposal requirements.

Most utility waste management facilities were not designed to provide a high level of protection against leaching. Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination. Although most of the materials found in these wastes do not cause much concern (for example, over 95 percent of ash is composed of oxides of silicon, aluminum, iron, and calcium), small quantities of other constituents that could potentially damage human health and the environment may also be present. These constituents include arsenic, barium, cadmium, chromium, lead, mercury, and selenium. At certain concentrations, these elements have toxic effects.

ES-4

To assess the potential threat to health and the environment posed by these wastes and to document any specific damage cases, EPA, other agencies, and various private organizations sponsored several studies. The main research efforts cited in this Report to Congress are a 1985 study by Arthur D. Little, Inc. for EPA, which characterized the environmental effects of waste disposal at several utility disposal sites, and a series of reports submitted to the Agency in 1982 by the Utility Solid Waste Activities Group, the Edison Electric Institute, and the National Rural Electric Cooperative Association.

The findings of these various research efforts indicate that most coal combustion wastes do not exhibit any of the four hazardous characteristics defined in RCRA Subpart C. The results of a substantial number of extraction procedure tests were examined; these tests indicated that metals do not generally leach out of coal combustion wastes at levels classified as hazardous under RCRA. The only metals which were found in any ash or sludge samples at "hazardous" levels were cadmium and arsenic. For boiler cleaning wastes, chromium and lead were sometimes found at levels classified as hazardous under RCRA. This waste stream was also found to be corrosive in a number of samples. Results of EP Tests performed on co-disposed high and low volume wastes indicate, however, that boiler cleaning wastes do not exhibit hazardous characteristics when co-disposed with ash.

While most of the laboratory results indicated that coal combustion wastes do not possess RCRA hazardous characteristics, in some instances, data on actual field observations indicate that migration of potentially hazardous constituents from utility waste disposal sites has occurred. For example, observed

ES-5

concentrations of contaminants found in ground water downgradient from the sites exceed the Primary Drinking Water Standards about 5 percent of the time. Although the magnitude of the PDWS exceedances are typically not many times greater than the standard, a large number of disposal facilities report at least one PDWS exceedance at some time.

While a causal connection cannot always be made between the utility waste disposal site and the presence of contaminants at concentrations in excess of these standards, the available information indicates that some ground-water contamination from utility disposal sites is indeed occurring. The actual potential for exposure of human and ecological populations is likely to be limited, however, since ground water in the vicinity of utility waste disposal sites is not typically used for drinking water; the concentrations of contaminants in the ground water also tend to be diluted in nearby surface water bodies. These surface water bodies are typically used by electric utilities in the power plants for cooling and other purposes.

The electric utility industry currently spends about \$800 million annually to dispose of its coal-fired combustion wastes. Under current practices, costs for waste management at most basic facilities range from as little as \$2 per ton to as much as \$31 per ton. Mitigative measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up ground-water contamination. These mitigative measures, which are currently used at some utility waste disposal sites, may reduce the likelihood of ground-water contamination, but may also substantially increase disposal costs. For example,

ES-6

the incremental cost of new waste disposal practices, excluding corrective action costs or higher recycling costs, could range up to \$70 per ton, or \$3.7 billion annually if all wastes were listed as hazardous. While substantial on a total cost basis, these increases would be unlikely to significantly affect the rate at which existing power plants consume coal. Due to the competitiveness of alternative fuels for electricity generation at future power plants, however, any increase in disposal costs could potentially slow the growth in electric utility coal consumption in future years. Moreover, if new disposal standards require corrective action measures as set forth in 40 CFR 264.100, the costs to utilities could be extremely high and could have a substantial effect on the utility industry.

Based on the findings from this Report to Congress, the Agency presents three preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D

ES-7

authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA

ES-8

believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . .," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

CHAPTER ONE

INTRODUCTION

This is the Environmental Protection Agency's Report to Congress on wastes from fossil fuel combustion, as required by section 8002(n) of the Resource Conservation and Recovery Act. It describes sources and quantities of utility waste, current utilization and disposal practices and alternatives to these practices, potential dangers to human health and the environment, and the costs of current and alternative waste management practices. This report is based on numerous literature reviews and contractor studies; EPA's RCRA Docket contains copies of the source materials that the Agency used in preparing this report.

1.1 Legislative History

Because Congress has amended the Resource Conservation and Recovery Act several times and EPA's regulatory program continues to evolve in response to these Congressional mandates and other additional information, a brief legislative and regulatory history is provided below.

The Resource Conservation and Recovery Act (RCRA, or the Act) of 1976 (Public Law 94-580) substantially amended the Solid Waste Disposal Act of 1965 and authorized the U.S. Environmental Protection Agency (EPA) to establish and enforce regulations concerning the identification, generation, transportation, and management of hazardous waste. These regulations would accomplish the Act's objectives of "...promote[ing] the protection of health and the environment ... and conserve[ing] valuable material and energy resources...."¹ RCRA comprises several subtitles, including Subtitle C-- Hazardous Waste

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Management, and Subtitle D-- State or Regional Solid Waste Plans. The intent of the regulations promulgated under Subtitle C of the Act is that wastes identified as hazardous be properly managed from "cradle to grave," that is, from the time they are generated, during transport, throughout their use in various applications, and during disposal. As provided under RCRA Subtitle D, other wastes not considered hazardous as defined under Subtitle C are subject to State regulations.

On December 18, 1978, EPA proposed the first regulations to implement Subtitle C. In the course of preparing these regulations, EPA recognized that certain very large-volume wastes (e.g., wastes generated by utility power plants) could require special treatment:

... The Agency has very little information on the composition, characteristics, and the degree of hazard posed by these wastes, nor does the Agency yet have data on the effectiveness of current or potential waste management technologies or the technical or economic practicability of imposing the Subpart D standards [current RCRA section 3004--Standards applicable to owners and operators of hazardous waste treatment, storage, and disposal facilities] on facilities managing such waste.

The limited information the Agency does have indicates that such waste occurs in very large volumes, that the potential hazards posed by the waste are relatively low, and that the waste generally is not amenable to the control techniques developed in Subpart D.²

Thus, the Agency proposed a limited set of regulations for managing large-volume wastes, pending an additional rulemaking. Until that rulemaking was completed, EPA proposed exempting utility wastes from storage and disposal regulations.

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On May 19, 1980, EPA promulgated the first regulations implementing Subtitle C of RCRA. By then, Congress was debating RCRA reauthorization, and both Houses had passed bills restricting EPA's ability to regulate utility wastes. Anticipating the enactment of legislation amending RCRA Section 3001, EPA excluded utility wastes from the promulgated regulations, writing in the preamble:

The United States Senate and House of Representatives have each recently passed a bill to reauthorize and amend RCRA (S.1156 and H.R.3994). Both bills contain amendments to Section 3001 which, if enacted, would repeal or temporarily suspend EPA's authority to regulate certain utility and energy development wastes as hazardous wastes under Subtitle C. These bills are now awaiting action by a conference committee. Because it appears likely that Congress will act before November 19, 1980 [the end of the six month comment period on the promulgated interim final regulations and the date on which they would take effect] to exempt these wastes, EPA has temporarily excluded them from this regulation (see section 261.4(b)). This exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted.³

In fact, Congress did act before November 19, 1980; the Solid Waste Disposal Act Amendments (Public Law 96-482) were passed in October 1980.

As anticipated, the amendments temporarily exempted from regulation fly ash waste, bottom ash waste, boiler slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. In section 8002(n), Congress directed EPA to produce a report on the kinds of waste generated by the combustion of coal and other fossil fuels, which would include an analysis of eight topics:

1. the source and volumes of such material generated per year;

1-4

2. present disposal and utilization practices;
3. potential danger, if any, to human health and the environment from the disposal and reuse of such material;
4. documented cases in which danger to human health or the environment from surface runoff or leachate has been proved;
5. alternatives to current disposal methods;
6. the costs of such alternatives;
7. the impact of those alternatives on the use of coal and other natural resources; and
8. the current and potential utilization of such materials.⁴

Finally, in section 3001(b)(3)(C), Congress directed that within six months after submitting this report, EPA must conduct public hearings and decide whether regulating the management of coal combustion wastes under Subtitle C is warranted. Once the decision is made, the Administrator must publish the Agency's regulatory determination in the Federal Register.

In a January 1981 letter,⁵ Gary Dietrich, then Associate Deputy Assistant Administrator for Solid Waste, provided an interpretation of RCRA regulations concerning the exemption from regulation of fossil fuel combustion waste.⁶ (This letter, as well as a February 18, 1981 memorandum that enclosed it as part of a mailing to EPA Regional Directors, is included as Appendix A.) The letter noted that the beneficial use of hazardous waste as a fuel was not subject to regulation, though it might well be subject to regulation in the future. This meant that utilities could burn as fuel a combination of

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hazardous waste and coal, as long as more than 50 percent of the mixture was comprised of coal. The letter also addressed disposal, noting that wastes produced in conjunction with the burning of fossil fuels (e.g., cleaning and other maintenance-related wastes) may be exempt from Subtitle C regulations provided they are mixed and co-disposed or co-treated with fossil fuel wastes and provided "there is no evidence of any substantial environmental danger from these mixtures."⁷ The letter concluded:

...Pending the completion of [further study on the hazards posed by waste from coal-fired utility plants and the collection of relevant data from the utility industry], EPA will interpret 40 CFR 261.4(b)(4) to mean that the following solid wastes are not hazardous wastes:

- (a) Fly ash, bottom ash, boiler slag, and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, where coal makes up more than 50 percent of the mixture.
- (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, boiler cleaning solutions, boiler blowdown, demineralizer reagent, pyrites, and cooling tower blowdown.

In November 1984, Congress reauthorized RCRA by passing the Hazardous and Solid Waste Amendments (HSWA). These amendments restricted the land disposal

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of certain hazardous wastes without treatment, established minimum technology requirements for landfills and surface impoundments, issued corrective action requirements for continuing releases at permitted facilities, and established interim status requirements for surface impoundments. Under this new legislation, EPA was granted some flexibility to promulgate regulations that take into consideration the unique characteristics of several types of large-volume wastes, including wastes generated by utility power plants. Specifically, if EPA determined that some or all of the wastes from fossil fuel combustion were subject to regulation under Subtitle C, EPA was empowered to modify the standards imposed by HSWA "...to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment."⁸

The HSWA Conference Report accompanying H.R. 2867 (which in its final amended form was passed by both Houses of Congress as Public Law 98-616) provides clarification:

This Amendment recognizes that even if some of the special study wastes [which include utility wastes as specified in Section 8002(n)] are determined to be hazardous it may not be necessary or appropriate because of their special characteristics and other factors, to subject such waste to the same requirements that are applicable to other hazardous wastes, and that protection of human health and the environment does not necessarily imply the uniform application of requirements developed for disposal of other hazardous wastes. The authority delegated to the Administrator under this section is both waste-specific and requirement-specific. The Administrator could also exercise the authority to modify requirements for different classes of wastes. Should these wastes become subject to the requirements of Section 3005(j), relating to the retrofit of surface impoundments, the Administrator could

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modify such requirements so that they are not identical to the requirements that are applied to new surface impoundments containing such wastes. It is expected that before any of these wastes become subject to regulation under Subtitle C, the Administrator will determine whether the requirements of Section 3004(c), (d), (e), (f), (g), (o), and (u), and Section 3005(j) should be modified.⁹

1.2. Scope and Sources

This report addresses only the wastes generated by coal-fired electric utility power plants. Because this industry generates the vast majority of all fossil fuel combustion waste (nearly 90 percent),¹⁰ EPA decided to focus its study in this area. This study does not address oil- and gas-fired electric utility power plants or coal, oil and gas-fired industrial boilers.

A number of research projects were undertaken to provide data for this report. EPA sponsored a major study of current coal ash and flue gas desulfurization waste management practices at coal-fired electric utility power plants.¹¹ In this study comprehensive environmental monitoring was conducted, which included characterizing the wastes, soils, ground water, and surface water at six disposal sites. The contractor (Arthur D. Little, Inc.) evaluated the environmental effects of the disposal practices used at these six sites and, by inference, what effects may be present at other utility waste disposal sites. They also performed extensive engineering and cost evaluations of disposal practices at the six sites.

EPA also sponsored a separate study effort to develop information on the incidences of ground water contamination resulting from utility waste management practices.¹² In this study, contamination was defined as the presence of hazardous constituents at levels above primary drinking water

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standards. The main source of information for this phase of the research was a review of case files at the state offices having responsibility for such matters.

In addition, the Agency also reviewed reports submitted by the Utility Solid Waste Activities Group (USWAG), the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association (NRECA).¹³ The reports present information on the sources, volumes, and physical and chemical characteristics of waste streams; ground-water monitoring results assembled from various utility plants; damage case information from various sources; costs of complying with hazardous waste regulations; and resource recovery opportunities using utility wastes.

EPA also has incorporated findings from several documents prepared by the Department of Energy (DOE) and the Electric Power Research Institute (EPRI).¹⁴ These reports examined the chemical composition of utility wastes, technologies for disposal and the costs associated with disposal, as well as results of leaching tests performed on utility wastes.

Finally, EPA gathered information from the Utility Data Institute's Power Statistics Database.¹⁵ This database contains information concerning the size of utility power plants, location of power plants, the types of disposal technologies employed by each power plant, and the amount of waste produced by site and by region. The information on location of power plants was combined with hydrogeologic, population, and ecological profiles of these locations to analyze the potential for exposure to coal combustion wastes.

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1.3 Organization

The following chapters of this report address the eight issues (enumerated earlier in this chapter) as required by Section 8002(n) as they apply to coal-fired combustion wastes generated by electric utilities. Chapter Two of this report provides an overview of the U.S. electric utility industry. Chapter Three examines the amount and types of wastes that are generated. Chapter Four discusses current waste management and disposal practices used by the electric utility industry, as well as alternatives to these practices; a review of applicable State regulations is included in this chapter. Chapter Five reviews the potential and documented impact of these wastes on human health and the environment, and Chapter Six evaluates costs associated with current waste disposal practices and additional costs that could be incurred under a variety of alternative waste management practices. Finally, Chapter Seven summarizes the conclusions contained in the previous chapters and presents recommendations.

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CHAPTER ONE

NOTES

- 1 Resource Conservation and Recovery Act of 1976 (RCRA), Section 1003(a).
- 2 Federal Register, Volume 43, No. 243, December 18, 1978, pp. 58991-58992.
- 3 Federal Register, Volume 45, No. 98, May 19, 1980, p. 33089.
- 4 RCRA, Section 8002(n).
- 5 Letter of January 13, 1981, from Gary N. Dietrich, Associate Deputy Assistant Administrator for Solid Waste, to Paul Elmer, Jr., Chairman of the Utility Solid Waste Activities Group.
- 6 See 40 CFR 261.4.
- 7 Gary N. Dietrich, January 13, 1981, op. cit.; for further information, see Congressional Record, February 20, 1980, p. H 1102, remarks of Congressman Beville; also see remarks of Congressional Record, February 20, 1980, p. H 1104, remarks of Congressman Rahall.
- 8 RCRA, Section 3004(x)
- 9 H.R. Report 98-1133, pp. 93-94, October 3, 1984.
- 10 Most fossil fuel combustion wastes are generated from coal. For example, as indicated in Physical-Chemical Characteristics of Utility Solid Wastes (by Tetrattech, Inc. for EPRI, September 1983), only about one percent of utility wastes are generated from oil; the remaining 99 percent is largely attributable to coal-fired electricity production. Of the coal consumed in the U.S., electric utilities burn nearly 90 percent (excluding metallurgical coal, which is not burned but is instead converted into coke primarily for making steel).
- 11 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants. Prepared for EPA's Office of Research and Development, EPA Contract #68-02-3167; June 1985.
- 12 Franklin Associates, Ltd., Survey of Groundwater Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.
- 13 USWAG is an informal consortium of approximately 65 electric utility operating companies, EEI, and NRECA. The primary source used in the preparation of this report was Report and Technical Studies On The Disposal and Utilization of Fossil-Fuel Combustion By-Products, USWAG, EEI, and NRECA, October 26, 1982.

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¹⁴ For example, see Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities; Prepared by Engineering-Science for DOE, DOE Contract Number DE-AC-01-79ET-13543, May 1983; Physical-Chemical Characteristics of Utility Solid Wastes, EPRI, September 1983; Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, Prepared by Western Research Institute, DOE Order Number DE-AP20-84LC00022, March 1984; and Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI, July 1984. More sources are included in the Bibliography.

¹⁵ Utility Data Institute's Power Statistics Database was developed under the auspices of the Edison Electric Institute to assist in their analysis of issues affecting the electric utility industry.

CHAPTER TWO

OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

This chapter provides a general overview of the U.S. electric utility industry. Section 2.1 summarizes electricity demand and discusses the overall structure of the electric utility industry. Section 2.2 focuses the discussion on the role that coal plays in generating electricity. Section 2.3 provides details of coal-fired electric generating technologies and the regional characteristics of coal-fired plants. The chapter concludes with a discussion in Section 2.4 of the waste streams that are produced during coal combustion.

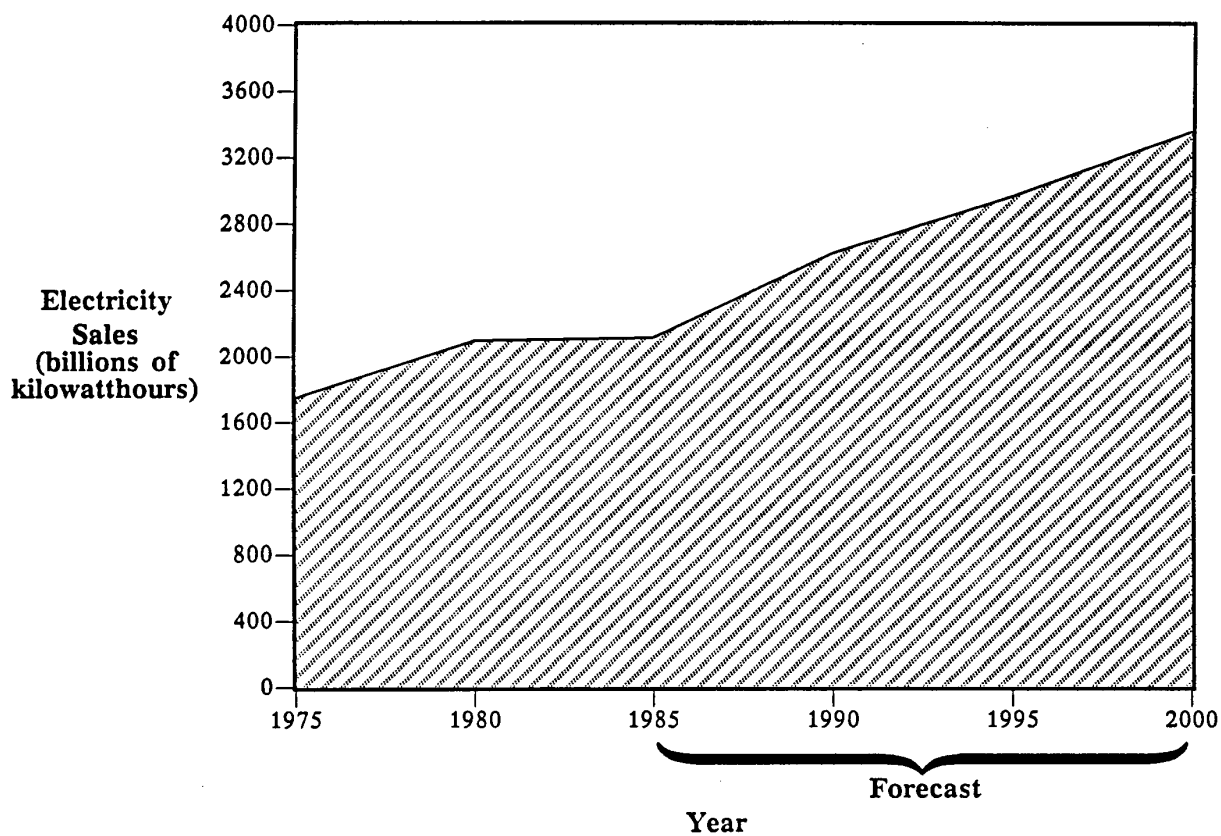
2.1 THE DEMAND FOR ELECTRICITY

The generation, transmission, and distribution of electricity is one of our nation's largest industries. With annual revenues in excess of \$140 billion and assets of about \$500 billion, the electric utility industry provides vital services to nearly every person in the U.S.¹

Total demand for electricity in the U.S. has increased substantially in recent decades and will likely continue to grow in coming years (see Exhibit 2-1). From the 1940's through the early 1970's, electricity demand grew at about 7 percent per year, doubling approximately every ten years. This growth slowed beginning with the 1973 OPEC oil embargo and subsequent changes in the energy markets such as fuel price increases, shifts in the economy to markets that require less electricity to meet their power needs, and energy conservation measures. Since 1973, growth in electricity demand has averaged

2-2

EXHIBIT 2-1
GROWTH IN ELECTRICITY DEMAND - 1975-2000



Sources: 1975-1985: Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (85/12), December 1985, p. 39.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

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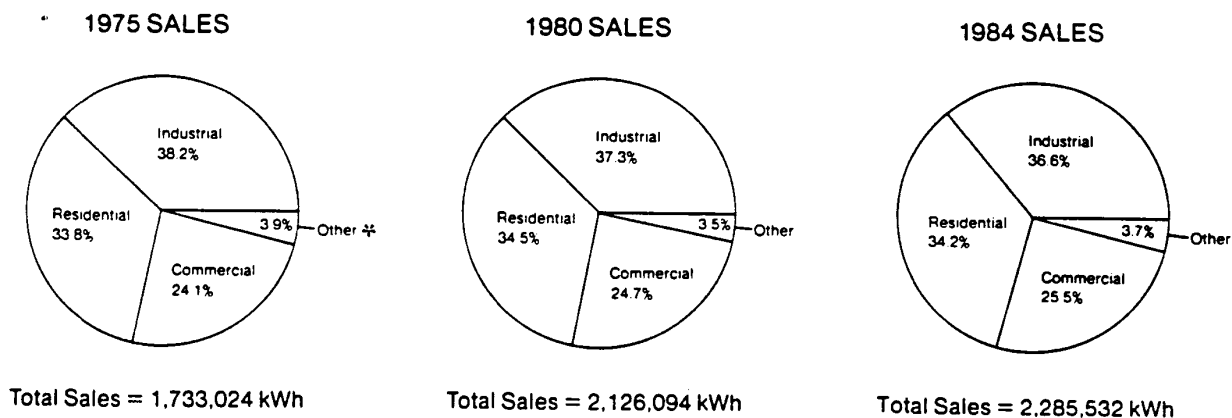
about three percent per year. Expectations are that electricity demand will continue to grow at an average rate of about 2 to 3 percent per year over the next several years.²

Every major segment of the U.S. economy relies on electricity to meet a portion of its energy needs. As shown in Exhibit 2-2, the demand for electricity is divided almost evenly between the industrial, commercial, and residential sectors. This demand for electricity has continued to increase over the last decade with total sales increasing from 1.7 million gigawatt-hours (Gwh) in 1975 to 2.3 million Gwh in 1985.³ As demand has increased, electricity sales patterns have remained relatively consistent. Industry continues to be the largest consuming sector, although industry's fraction of total sales has decreased by about 2.7 percent from 1975 to 1985, primarily due to an increased market share for the commercial sector (i.e., stores, office buildings, restaurants, etc.). Residential customers consume about one-third of all electricity for basic necessities such as lighting, heating, and electrical appliances.

Virtually every geographic area in the U.S. relies on electricity supplied by the electric utility industry. As shown in Exhibit 2-3, electricity demand is highest in the eastern half of the U.S., particularly in EPA Regions 3-6 (see Exhibit 2-4 for a map of these EPA Regions). This level of demand is not surprising considering that these areas are the most heavily industrialized and densely populated areas of the country.

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EXHIBIT 2-2
ELECTRICITY SALES BY YEAR AND CLASS OF SERVICE
(gigawatt-hours)



Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

*Includes street lighting, other public authorities, railroads and interdepartmental transfers within utilities (i.e., use of electricity by the utility itself).

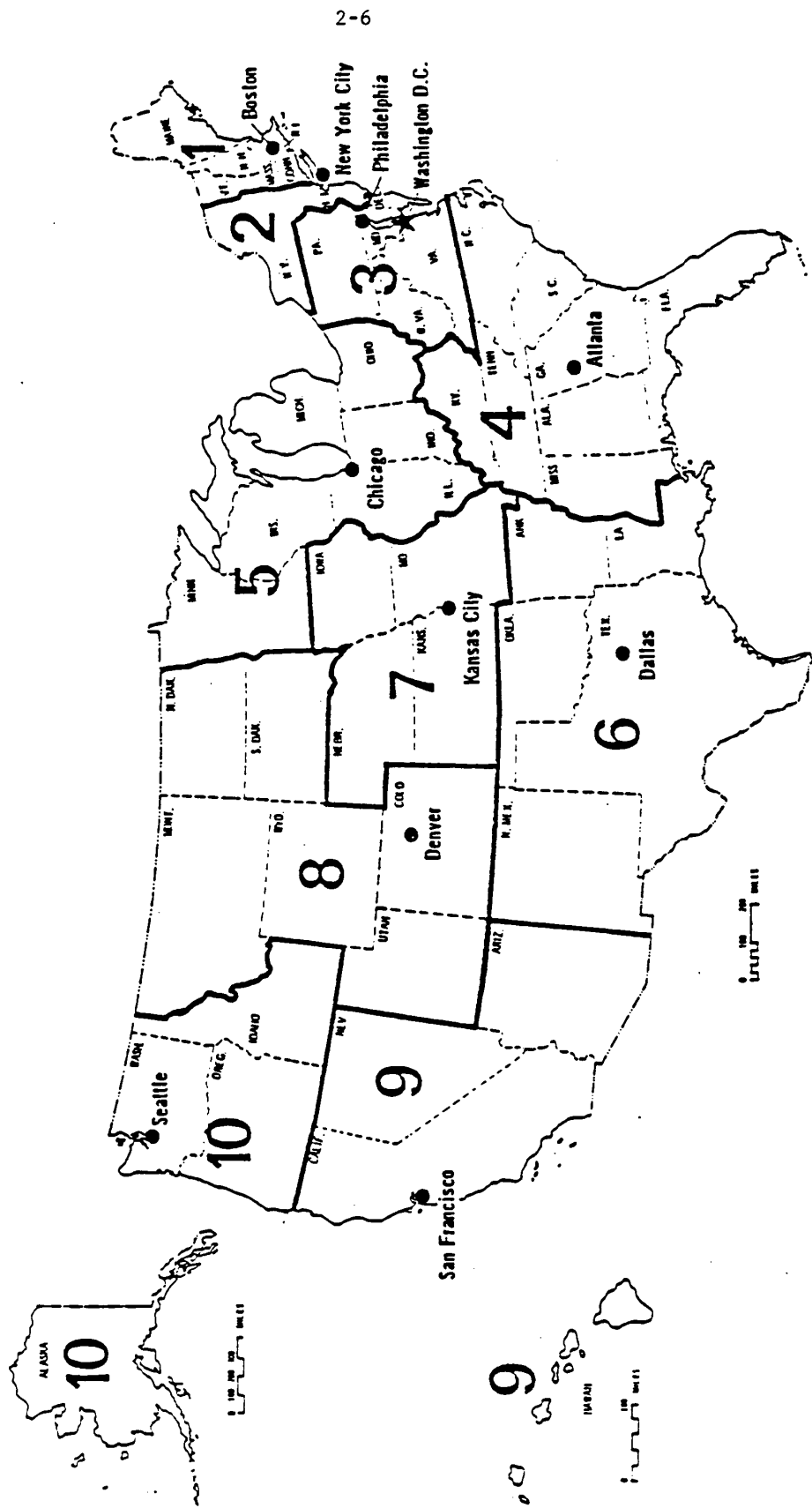
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EXHIBIT 2-3
ELECTRICITY DEMAND by EPA REGION
1985

<u>EPA Region</u>	<u>Millions of Kilowatt Hours</u>	<u>Percent of Total</u>
1	86,397	3.8
2	164,780	7.2
3	230,055	10.1
4	483,248	21.2
5	428,873	18.8
6	340,198	14.8
7	112,076	4.9
8	72,458	3.2
9	227,006	10.0
10	135,716	6.0
<hr/>		
Total U.S.	2,280,585	100.0

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

EXHIBIT 2-4
EPA FEDERAL REGIONS



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2.1.1 Structure of the U.S. Electric Utility Industry

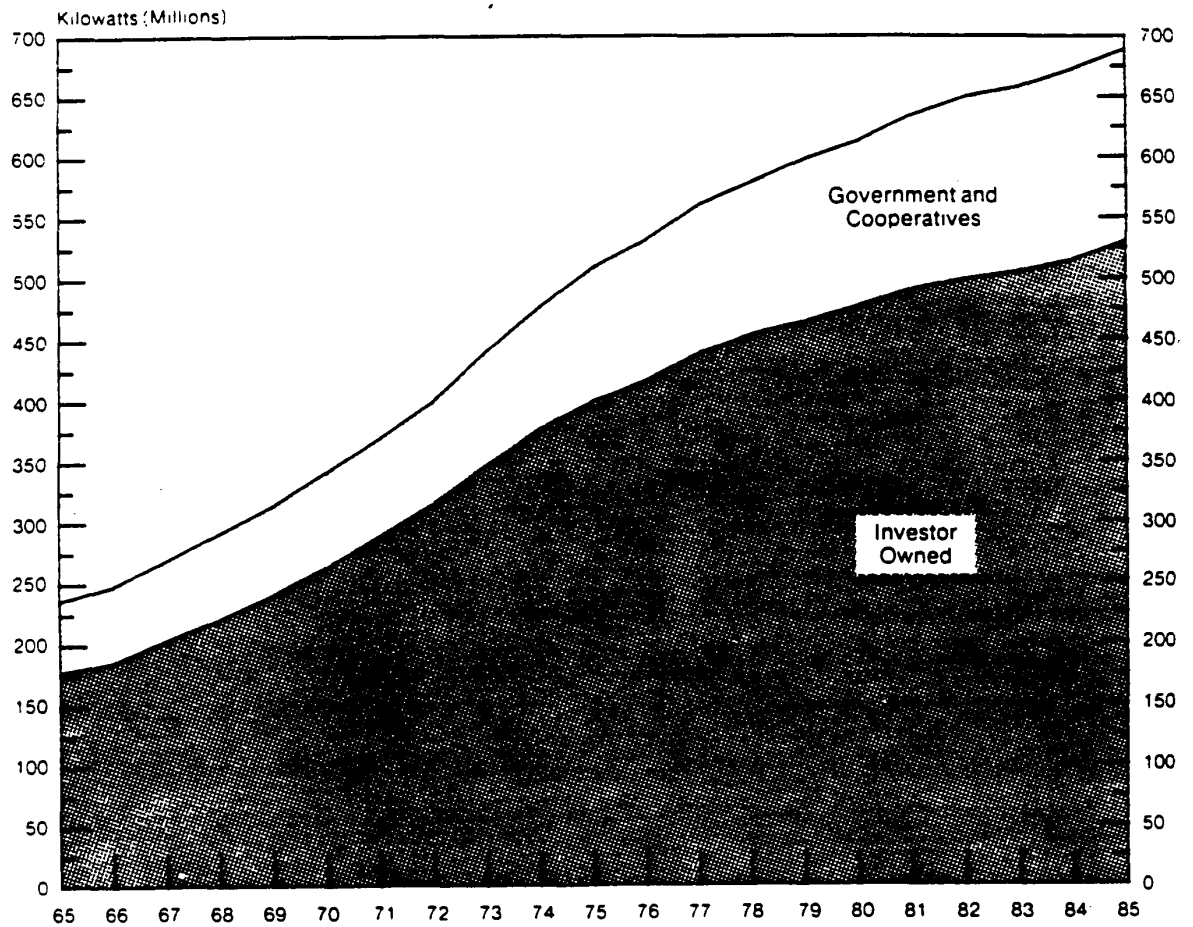
The U.S. electric power industry is a combination of private, Federal, and public nonprofit organizations. The distribution of capacity, generation, revenue, and sales differs widely among these ownership groups since each group has different objectives, organizational characteristics, and financing methods. Private investor-owned utilities dominate the U.S. electric utility industry as shown in Exhibit 2-5. Investor-owned utilities have historically served large consolidated markets to take advantage of economies of scale. Federal, municipal, cooperative, and other publicly-owned utilities have generally served smaller markets where local governments or nonprofit organizations have had access to limited supplies of less expensive Federal power or to government-supplied capital for power plant construction. These circumstances have allowed municipal, cooperative, or other publicly-owned utilities to predominate in areas not traditionally served by investor-owned utilities.⁴ A brief discussion of each type of organization is provided below.

2.1.1.1 Investor-Owned Utilities

Investor-owned utilities account for about three-quarters of all U.S. electric utility generating capacity, generation, sales, and revenue. Investor-owned utilities are privately owned, profit-oriented businesses granted service monopolies in certain geographic areas. As franchised monopolies, they are obligated to provide service to all customers within their geographic area. In providing this service, investor-owned utilities are required to charge reasonable prices, to charge similar prices to similar

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EXHIBIT 2-5
GENERATING CAPACITY IN THE UNITED STATES



Source: Edison Electric Institute, Statistical Yearbook for the Electric Utility Industry/1985, December 1986.

customers, and to give customers access to services under similar conditions.⁵ Investor-owned utilities operate in all states except Nebraska (which depends primarily on public power districts and rural electric cooperatives for electricity). In 1984, consumers paid an average of 6.5 cents per kilowatt-hour (kwh) for privately-produced power compared to the industry average from all ownership groups of 6.3 cents per kilowatt-hour (an average customer consumed 23,150 kwh in 1984).⁶

2.1.1.2 Federal Power

The U.S. Government is the second largest producer of electricity in the United States with roughly 10 percent of total U.S. generation and generating capacity. Consumers of Federal power paid the lowest rate among the different ownership groups -- only 3.5 cents per kwh on average in 1984, (compared to an industry average of 6.3 cents per kwh).⁷ Federal power production is designed to provide power at the lowest possible rate, with preference in the sale of electricity given to public entities and cooperatives.⁸ In this role the Federal Government is primarily a generator and wholesaler of electricity to other organizations, rather than a direct distributor to electricity consumers.⁹

2.1.1.3 Municipal Utilities

Municipal utilities are nonprofit local government agencies designed to serve their customers at the lowest possible cost. Most municipal utilities simply distribute power obtained from one of the other ownership groups (e.g., Federal facilities), although some larger ones also generate and transmit

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power. Municipally-owned electric utilities rank third in the amount of installed capacity (5.5 percent of total generating capacity), but comprise the single most numerous ownership group (1,811 utilities in 1984).¹⁰ Average revenue per kwh sold in 1984 was 5.69 cents compared to an industry average of 6.3 cents per kwh. Municipal utilities are exempt from local, state, and Federal taxes and have access to less expensive capital via public financing and less expensive Federal power. As a result, municipal utilities can generally afford to charge less than investor-owned utilities for the power they produce.¹¹

2.1.1.4 Cooperatives

Rural electric cooperatives are owned by and provide electricity to their members and currently operate in 46 states. They have the lowest amount of installed capacity among all ownership categories (24.7 gigawatts in 1984 or less than 4 percent of all capacity).¹²

In 1984, average revenue for cooperatives from sales to consumers was 6.7 cents per kwh, the highest of all ownership types (the industry average was 6.3 cents per kwh). Large construction programs in the 1970's usually account for the high rates.¹³

2.1.1.5 Other Public Entities

There are a variety of other public organizations that provide electric power, including public power districts, state authorities, irrigation districts, and various other State organizations. These other public entities

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operated a combined total of 32.8 gigawatts in 1984, or about 5 percent of all generating capacity in the U.S.¹⁴ The public power districts are concentrated in five states -- Nebraska, Washington, Oregon, Arizona, and California. The average price paid for electricity from all of these entities was 4.37 cents per kwh in 1984, compared to an industry average of 6.3 cents per kwh.¹⁵

2.1.2 Economic and Environmental Regulation of the Electric Utility Industry¹⁶

The electric utility industry is regulated by several different regulatory bodies at both the Federal and State levels. According to the U.S. Department of Energy: "The basic purpose of public utility regulation is to assure adequate service to all public utility patrons, without discrimination and at the lowest reasonable rates consistent with the interests both of the public and the electric utilities."¹⁷ This regulation involves both economic and environmental objectives. As natural monopolies, electric utilities are regulated to ensure that adequate, reliable supplies of electric power are available to the public at a reasonable cost. Additionally, since the operations of electric utilities can affect environmental quality, they are regulated to ensure the protection of the nation's air and water resources. This section briefly reviews the main regulatory bodies that affect the electric utility industry.

2.1.2.1 Federal Regulation

There are five major organizations at the Federal level that regulate some aspect of the electric utility industry -- the Federal Energy Regulatory Commission (FERC), the Economic Regulatory Administration (ERA), the

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Securities and Exchange Commission (SEC), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA).

- The Federal Energy Regulatory Commission (FERC) oversees various aspects of the electric utility, natural gas, hydroelectric, and oil pipeline industries. FERC approves the rates and standards for wholesale interstate electricity sales between investor-owned utilities and other investor-owned utilities, municipals, or cooperatives (these sales are about 15 percent of total U.S. electricity sales).¹⁸ It determines whether these rates are reasonable and non-discriminatory. FERC also oversees utility mergers and the issuance of certain stock and debt securities, approves the rates of Federal Power Marketing Administrations, and administers agreements between utilities concerning electricity transmission.
- The Economic Regulatory Administration (ERA) has several responsibilities, including administering a program to ensure that all future power plants have the potential to burn coal, regulating international electricity transmission connections, and licensing exports of power.
- The Securities and Exchange Commission (SEC) is an independent regulatory agency established to regulate interstate transactions in corporate securities and stock exchanges. With respect to the electric utility industry, the SEC regulates the purchase and sale of securities, utility properties, and other assets.
- The Nuclear Regulatory Commission (NRC) is involved only in the regulation of nuclear facilities owned and operated by the utility industry. Its main responsibilities include licensing the construction and operation of nuclear facilities, licensing the possession, use, transportation, handling, and disposal of nuclear materials, licensing the export of nuclear reactors and the import and export of uranium and plutonium, and regulating activities affecting the protection of nuclear facilities and materials.

In addition to these regulatory bodies, the Environmental Protection Agency (EPA) is the main Federal regulatory authority for protecting the nation's air and water quality. As part of its overall authority, EPA sets limits on the level of air pollutants emitted from electric power plants and develops regulations to control discharges of specific water pollutants.

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Throughout this Report to Congress key regulations that affect the electric utility industry are discussed. While EPA often takes the Federal lead when these regulations are developed, the Agency also works closely with the States since they often retain primary authority for implementing and enforcing standards (for example, see Section 4.1 on state regulation of coal combustion wastes).

2.1.2.2 State Regulation

States are also involved in the environmental and economic regulation of the electric utility industry. As mentioned above, the States often share regulatory authority with the various Federal organizations. For environmental regulation the States often have their own environmental protection agencies to implement and enforce State and Federal environmental regulations. For example, they are responsible for drafting State Implementation Plans (SIP) that must be approved by the U.S. EPA to attain National Ambient Air Quality Standards (NAAQS). Similarly, as will be discussed in greater detail in Chapter Four, the States have authority for implementing and enforcing regulations concerning the disposal of solid wastes under Subtitle D of RCRA. Environmental regulations for which the States exercise regulatory authority are discussed throughout this Report to Congress.

States are also very involved in the economic regulation of the electric utility industry. The primary goals of state economic regulation is usually to provide adequate nondiscriminatory service to electricity consumers at reasonable prices.¹⁹ This is usually accomplished by state regulatory

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agencies such as public utility commissions. The amount of authority these state regulatory agencies have can differ widely from state to state. However, these agencies usually have the authority to approve electricity price levels and the rates of return allowed for utility stockholders. State regulators also approve the franchise under which the utility operates. Licensing for construction and operation and approval of the sites at which power plants will be built are also important functions of some state regulatory commissions. Other areas into which some commissions have entered to ensure that utility activities protect the public interest include setting rules about when competitive bids are required, promulgating company performance standards, deriving methods for allocating power during shortages, establishing billing and safety rules, and promoting conservation.²⁰

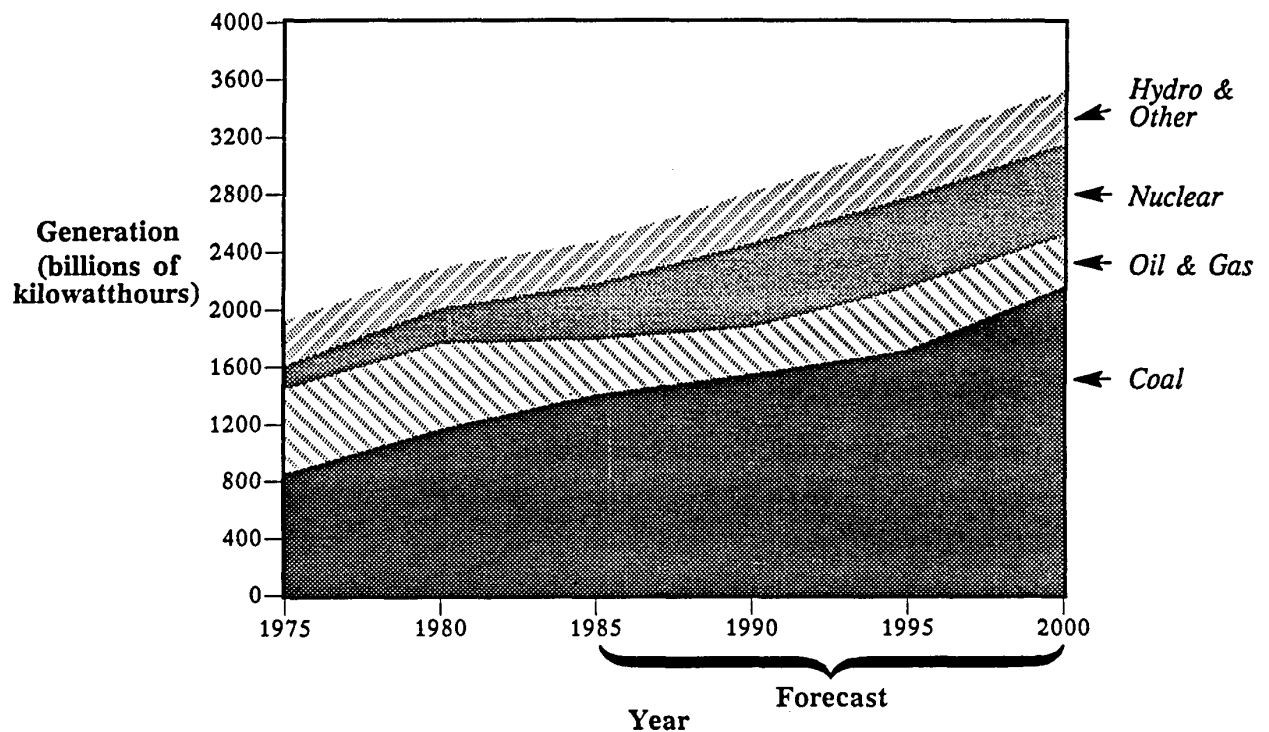
2.2 IMPORTANCE OF COAL TO ELECTRIC UTILITIES

Electric utilities use many different technologies and energy sources to generate electricity. At present, as shown in Exhibit 2-6, over 70 percent of electricity in the U.S. is generated by the combustion of fossil fuels (coal, oil and natural gas); most of the remaining 30 percent is generated by hydroelectric plants and nuclear power plants. A small portion of electricity demand is satisfied by alternative sources such as geothermal energy, renewable resource technologies (e.g., wood, solar energy, wind), purchased power from industrial and commercial cogeneration (cogeneration is the simultaneous production of electricity and process steam; the electricity is typically used by the cogenerator or sold to another industry while the steam is used for various production processes), and power imports (primarily from Canada).

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EXHIBIT 2-6

ELECTRICITY GENERATION BY PRIMARY ENERGY SOURCE
1975-2000



Source: 1975-1985: Energy Information Administration, Electric Power Monthly DOE/EIA-0226 (85/12), December 1985, p. 10.

1985-2000: ICF Incorporated, Analysis of 6 and 8 million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

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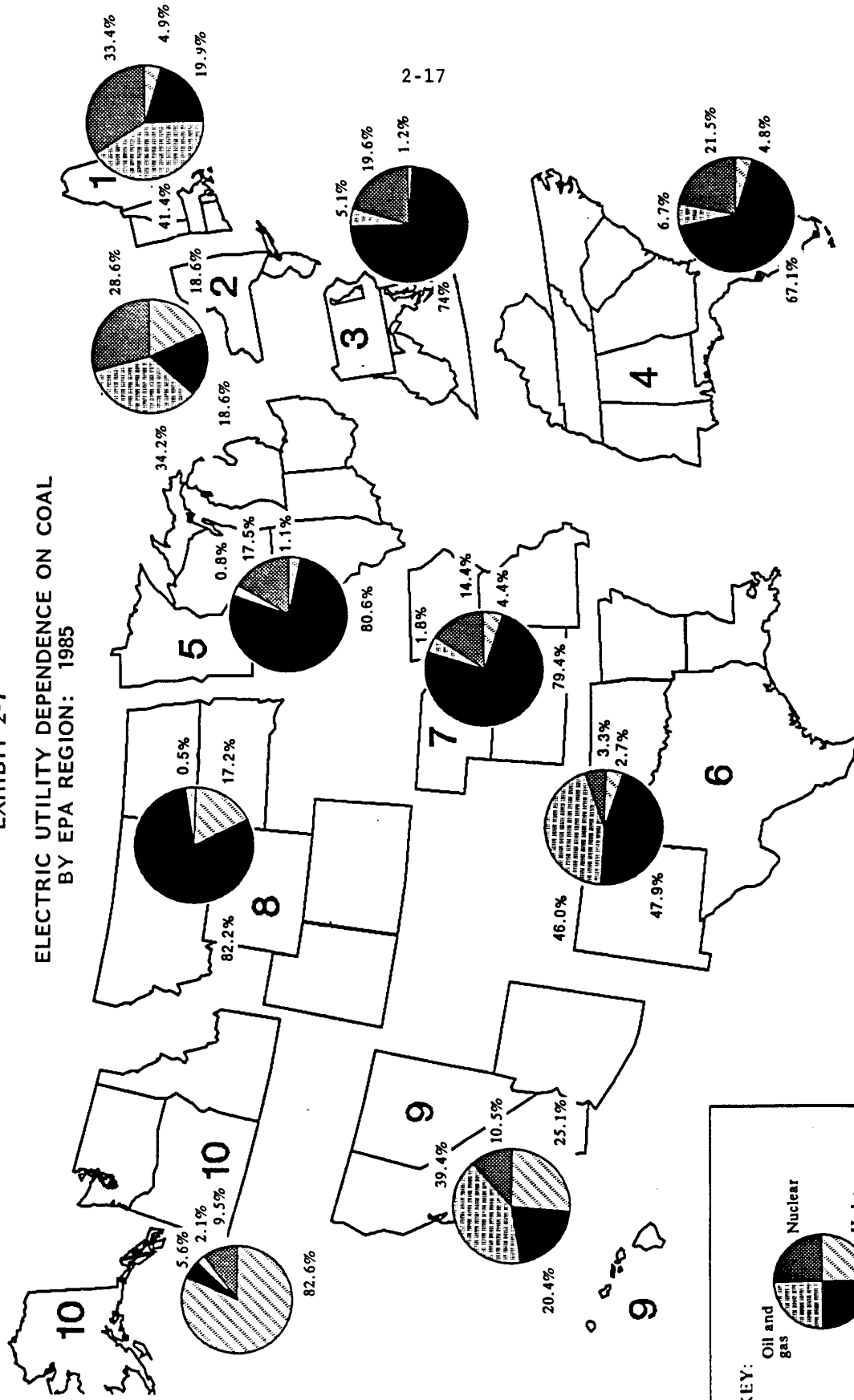
In 1984, coal accounted for more than half of all the electricity generated in the U.S.²¹ The portion of electricity generated from coal is expected to remain at about this level throughout the rest of the century since coal-fired generation is expected to remain economically attractive. The relative contribution to total generation made by other fossil fuels and by hydroelectric power will likely continue to decline, while the contribution made by nuclear power plants will likely increase for the next few years as several new units come on-line. However, the addition of nuclear plants beyond those now under construction will be minimal, leading to an eventual decline in nuclear's relative contribution. Cogeneration, power imports, and emerging technologies are expected to continue to grow, but their share of total generation will remain small. As a result, coal will continue to be the major fuel source for electricity generation.

The extent of the electric utility industry's dependence on coal varies geographically. Exhibit 2-7 shows that coal accounts for over three-quarters of electricity generation in some regions, but less than half in others. For example, in the far West and southern Plains states, the local availability of oil, gas, and hydroelectric power has limited regional dependence on coal. In many of the eastern regions, where coal is relatively more accessible and less costly than oil or gas, coal is significantly more dominant. Despite these regional variations, however, coal-fired electricity generation is an important source of electricity in most regions of the United States.

The use of coal by electric utilities has also made the coal and electric utility industries highly interdependent; not only does coal-fired electricity generation account for over half of the electricity produced in the U.S., but

EXHIBIT 2-7

ELECTRIC UTILITY DEPENDENCE ON COAL
BY EPA REGION: 1985



KEY:

Oil and gas

Nuclear

Hydro

Coal

Percentages represent the proportion of the total electricity generated in the region by each type of fuel.

Source: Energy Information Administration, Electric Power Annual 1985, DOE/EIA-0348(85), pp.17-30.

2-18

the electric utility industry is the largest customer of the coal industry, purchasing approximately three-quarters of all coal mined, as shown in Exhibit 2-8. This interdependence has increased as electric utility coal consumption has grown from 406 million tons in 1975 to over 600 million tons in 1985.²² Moreover, electric utility coal consumption is expected to continue to increase to about 1 billion tons by the year 2000.

2.3 OVERVIEW OF COAL-FIRED POWER PLANTS

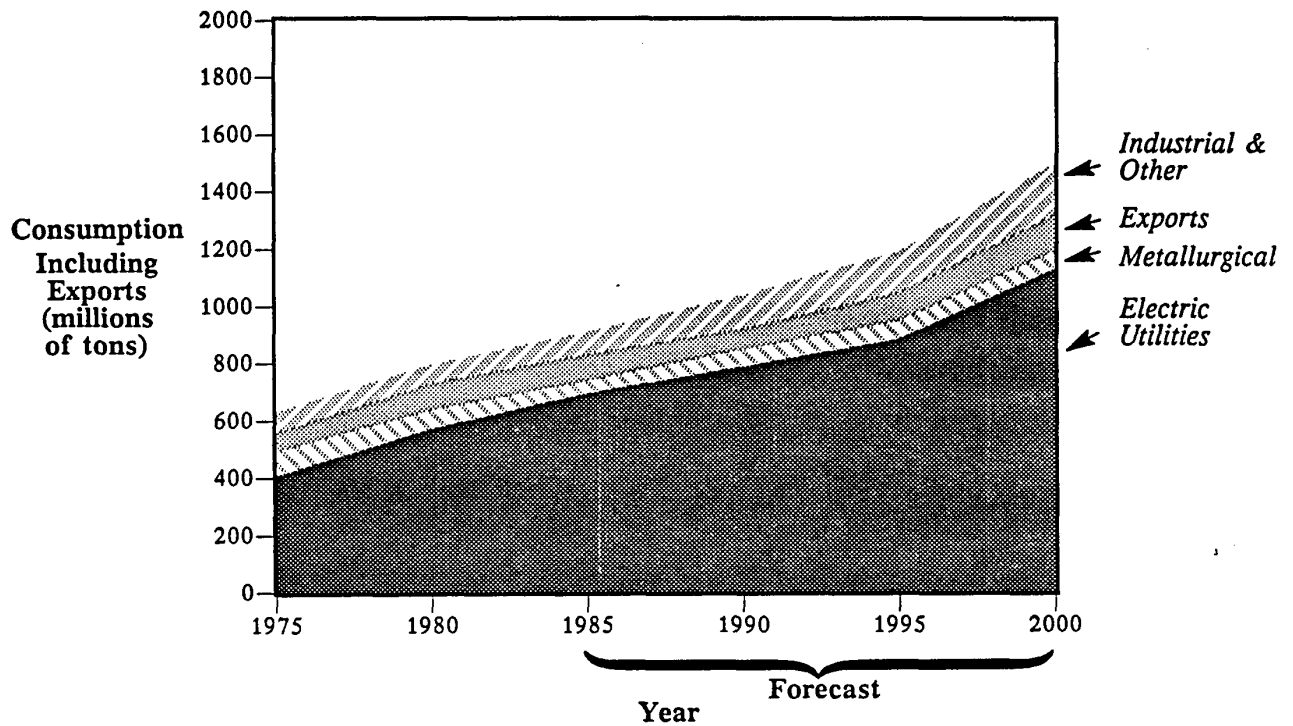
Coal-fired power plants can vary greatly in terms of their generating capacity and the type of boiler technology they employ which, in turn, can affect the amount and type of combustion wastes produced. This section discusses the geographic differences in the size of plants and generating units and describes the three main boiler types along with the regional importance of each.

2.3.1 Regional Characteristics of Coal-Fired Electric Generating Plants

Coal-fired power plants can range in size from less than 50 MW to larger than 3000 MW. In many cases, particularly at the larger power plants, one power plant site may be the location for more than one generating unit (a generating unit is usually one combination of a boiler, turbine, and generator for producing electricity). Exhibit 2-9 shows the number of coal-fired power plants and number of units in each EPA region and their average size in megawatts. On average, each power plant site is comprised of about three generating units. The average generating capacity of coal-fired power plants in the U.S. is approximately 584 MW, with an average unit size of 257 MW.

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EXHIBIT 2-8
U.S COAL CONSUMPTION BY SECTOR
1975-2000



Sources: 1975-1985: Energy Information Administration, Annual Energy Review 1985, DOE/EIA-0384 (85), April 1985, pp. 167, 169.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

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EXHIBIT 2-9

TOTAL NUMBER AND AVERAGE SIZE OF COAL-FIRED PLANTS AND UNITS

<u>EPA Region</u>	<u>Number of Plants</u>	<u>Average Size (MW)</u>	<u>Number of Units a/</u>	<u>Average Size a/ (MW)</u>
1	6	374	18	158
2	17	297	39	138
3	57	753	144	308
4	93	799	295	301
5	171	492	492	185
6	39	852	87	580
7	66	400	149	186
8	48	454	109	250
9	13	603	34	383
10	<u>4</u>	<u>479</u>	<u>11</u>	<u>382</u>
U.S. Total	514	584	1378	257

Source: Utility Data Institute Power Statistics Database.

a/ The total amount of generating capacity indicated by multiplying the number of units by their average size (e.g., 1378 units X 257 Mw = 354,146 Mw) is greater than the amount indicated by multiplying the number of power plants by their average (e.g., 514 plants X 584 Mw = 300,176 Mw) because the information in the UDI Power Statistics Database by generating units includes units planned, currently under construction, etc. while the information by power plants refers only to power plants currently operating.

2-21

Regional averages for power plant size range from 297 MW in Region 2 to 852 MW in Region 6. Unit sizes range from an average of 138 Mw in Region 2 to 580 Mw in Region 6. Individual power plants and units can be larger or smaller than these averages indicate.

The majority of coal-fired plants (60%) are smaller than 500 MW, while only about 4 percent of U.S. coal-fired power plants have a generating capacity exceeding 2000 MW. Exhibit 2-10 shows the distribution of coal-fired plant sizes across EPA regions.

2.3.2 Electricity Generating Technologies

The basic process by which electricity is produced with coal is shown in Exhibit 2-11. When coal is burned to produce electricity, there are three key components that are critical to the operation of the power plant: the boiler, turbine, and generator. As coal is fed into the boiler, it is burned in the boiler's furnace. In the boiler there are a series of water-filled pipes. As heat is released during combustion, the water is converted to steam until it reaches temperatures that can exceed 1000°F and pressures that approach 4000 pounds per square inch. This high pressure, high temperature steam is then injected into a turbine, causing the turbine blades to rotate. The turbine, in turn, is connected to a generator, so the mechanical energy available from the rotating turbine blades is transformed into electrical energy. The electricity produced by this process is distributed via transmission lines to residential, commercial, and industrial end-users who rely on the power to meet their electrical requirements. Although each step of this process is critical to the production of electricity, this study focuses on boilers only

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EXHIBIT 2-10

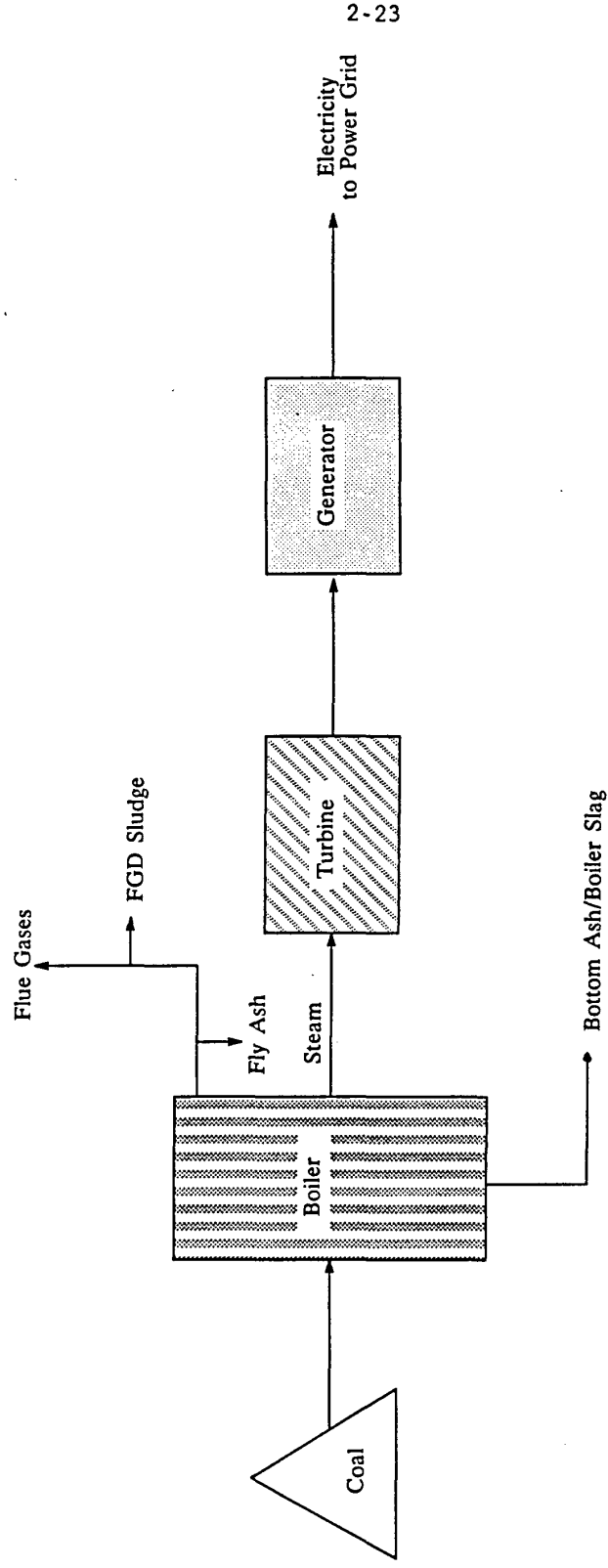
RANGE OF COAL-FIRED POWER PLANT SIZES
(number of plants)

EPA Region	Power Plant Size					Total
	<100 MW	101-500 MW	501-1000 MW	1001-2000 MW	≥2000 MW	
1	1	4	0	1	0	6
2	6	6	5	0	0	17
3	6	23	11	14	3	57
4	15	31	17	23	7	93
5	63	51	23	29	5	171
6	10	4	10	12	3	39
7	25	24	8	7	2	66
8	18	14	10	4	2	48
9	5	2	4	1	1	13
10	<u>2</u>	<u>0</u>	<u>1</u>	<u>1</u>	<u>0</u>	<u>4</u>
U.S. Total	151	159	89	92	23	514

Source: Utility Data Institute Power Statistics Database.

EXHIBIT 2-11

PROCESS FOR GENERATING ELECTRICITY
AT COAL-FIRED POWER PLANTS



Source: ICF Incorporated

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since it is in the boiler where the combustion wastes are produced as the coal is burned.

There are three main types of boilers: (1) pulverizers, (2) cyclones, and (3) stokers. As discussed below in greater detail, the key differences between these boiler types are operating size and the procedures used for handling and burning the coal. Pulverized coal boilers are so-named because the coal is finely pulverized prior to combustion; most utility boilers are this type. Cyclones have been used in past utility applications, but have not been built recently. They are called cyclones because of the cyclone-like vortex created by the coal particles in the furnace during combustion. Stoker boilers are usually used when smaller capacities are required (e.g., 20-30 MW) and burn coal in a variety of sizes.

A brief description of each of these coal combustion technologies follows.²³

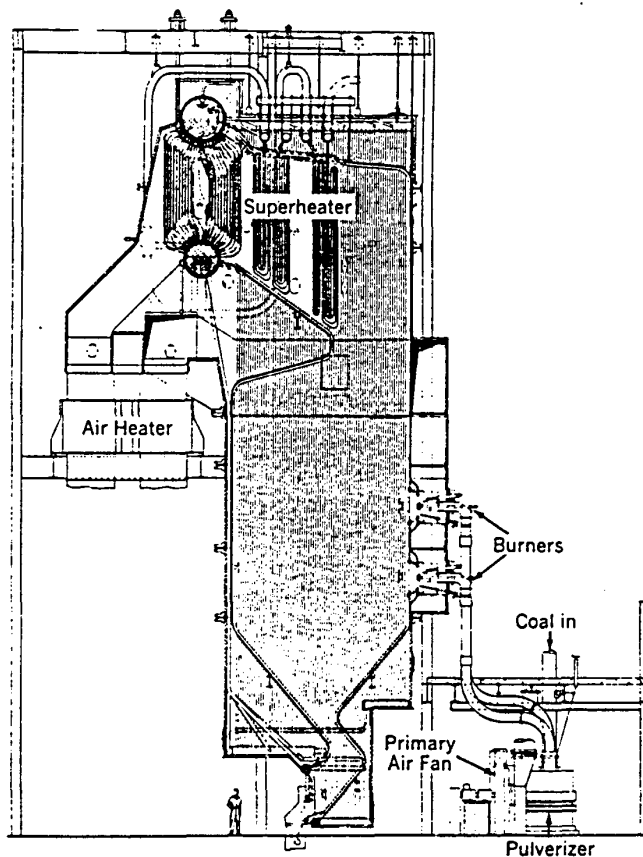
2.3.2.1 Pulverized-Coal Boiler

Exhibit 2-12 shows a typical pulverized-coal boiler setup. In a pulverized coal boiler, coal is ground to a fine size (about 200 mesh, which is powder-like) in a pulverizer or mill. The pulverized fuel is then carried to the burners by forced air injection and blown into the furnace, where it is burned in suspension. Much of the ash remaining after combustion remains airborne and is carried from the furnace by the flue gas stream (i.e., it becomes fly ash; see Chapter Three for a more detailed discussion of types of waste and how they are produced). Some ash is deposited on the furnace walls,

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EXHIBIT 2-12

DIAGRAM OF A PULVERIZED COAL BOILER



Two-drum boiler direct-fired with pulverized coal.

Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY 1978.

2-26

where it agglomerates and may sinter or fuse. Ash that falls to the bottom of the furnace is removed via an ash hopper. Ash deposits and slagging are more of a problem in pulverized coal boilers than in stoker boilers.

Most modern pulverized-coal boilers have dry-bottom furnaces; that is, the ash is intended to be removed as a dry solid before complete melting occurs. As a result, for dry-bottom boilers, the ash-fusion temperature (the melting point) of the coal must be high enough to prevent the ash from becoming a running slag (i.e., a liquid form). Wet-bottom, or slag-tap, pulverized-coal boilers are designed to remove the ash as a flowing slag. These boilers depend on lower ash-fusion temperature coals so that the ash will melt to form slag for easier removal.

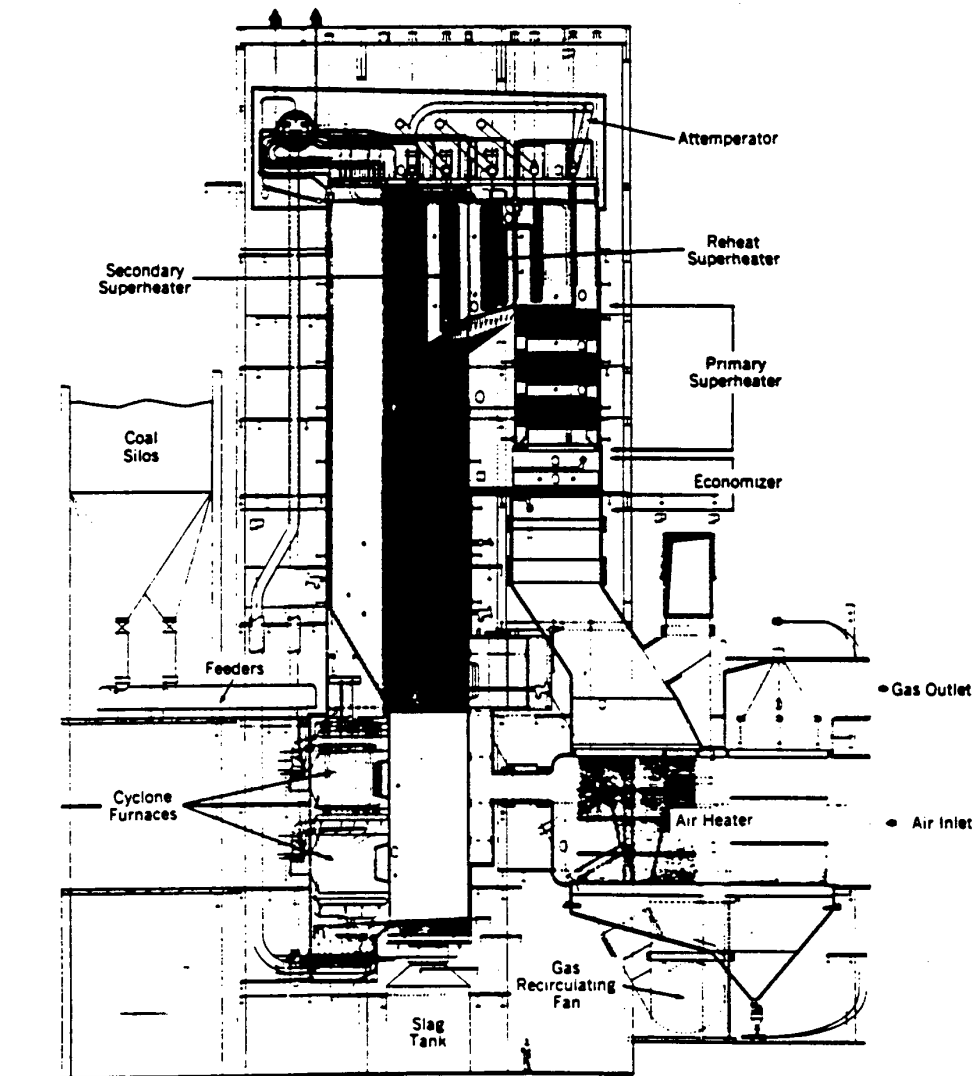
2.3.2.2 Cyclones

The cyclone furnace consists of a water-cooled horizontal furnace in which crushed coal is fired and heat is released at high rates, as shown in Exhibit 2-13. The temperature inside the furnace may reach 3000°F, which is sufficient to melt the ash into a liquid slag that forms on the walls of the furnace. Air circulation within the furnace typically creates a cyclone-like vortex that not only helps the coal to burn in suspension but also causes many coal particles to impinge upon the slag-covered walls of the furnace. This tendency for coal particles to adhere to the walls of the cyclone boiler aids the combustion process because the coal particles will burn more thoroughly before reaching the bottom of the boiler. Most of the ash is retained in the slag layer, thus minimizing the amount of fly ash that is carried out of the boiler. The slag,

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EXHIBIT 2-13

DIAGRAM OF A CYCLONE BOILER



Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY, 1978.

2-28

or melted ash particles, is typically removed at the bottom of the furnace.

The cyclone offers the advantage of being able to burn low ash-fusion coals that create problems when burned in most conventional pulverized-coal burners. The cyclone design also helps to minimize erosion and fouling problems in the boiler. The smaller amounts of fly ash created compared to other boiler types reduces the costs associated with particulate collection.

2.3.2.3 Stokers

Stokers are designed to mechanically feed coal uniformly onto a grate within a furnace. Because most of the combustion takes place in the fuel bed, not in suspension within the furnace, the heat release rate of this type of boiler is lower than it is for pulverizers or cyclones. As a result, stokers are generally designed for smaller-sized applications. In fact, this boiler type is used by many manufacturing industries, but has seen only limited use by electric utilities.

Stokers are classified by the method of feeding fuel to the furnace and by the type of grate. The three most important stoker types include:

- 1) the spreader stoker, the most popular type of overfeed stoker,
- 2) other overfeed stokers, such as the chain-grate, travelling-grate stoker, or the vibrating-grate stoker, and
- 3) the underfeed stoker.

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The major features of each are summarized in Exhibit 2-14. An illustration of a spreader stoker is provided in Exhibit 2-15.

Use of the different boiler types varies by geographic region. As shown in Exhibit 2-16, about three-fourths of all boiler capacity in the U.S. uses pulverizers, with most of these dry-bottom pulverizers. Cyclones are the next most prevalent boiler type, representing only about 8 percent of all boilers. Stokers represent less than one-half of one percent of the total; due to their size limitations stokers are used primarily in other industrial applications for the production of steam.

Exhibit 2-17 shows the distribution of average capacity for each boiler type by EPA region. The range in average sizes is most pronounced in dry bottom boilers (127.8-610.0 MW), which reflects their substantial flexibility in terms of size and dominance in electric utility applications. Stokers tend to have the smallest capacities (an average of 14 MW nationwide), limiting their usefulness in utility applications compared to all of the other boiler types.

2.4 COAL CONSTITUENTS AND BY-PRODUCTS

Despite its attractiveness as a power plant fuel, coal has its drawbacks. As a solid fuel, coal is often more difficult and more costly to transport, store, and burn than oil or gas. Also, coal's many impurities require environmental control at various stages of the fuel cycle.

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EXHIBIT 2-14

CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

<u>Stoker Type & Subclass</u>	<u>Typical Maximum Capacity Range (pph steam) a/</u>	<u>Burning Rate (Btu/hr/ft²) b/</u>	<u>Characteristics</u>
1. Spreader			
- Stationary and dumping grate	20,000-80,000	450,000	Capable of burning a wide range of coals, best ability to follow
- Travelling grate	100,000-400,000	750,000	fluctuating loads, high
- Vibrating grate	20,000-100,000	400,000	fly ash carry over, low load smoke.
2. Overfeed			
- Chain grate and travelling grate	20,000-100,000	600,000	Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
- Vibrating grate	30,000-150,000	400,000	Low maintenance, low fly ash carry over, capable of burning wide variety of weakly caking coals, smokeless operation over entire range.
3. Underfeed			
- Single or double retort	20,000-30,000	400,000	Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly ash carry over, suitable for continuous-load operation.
- Multiple retort			

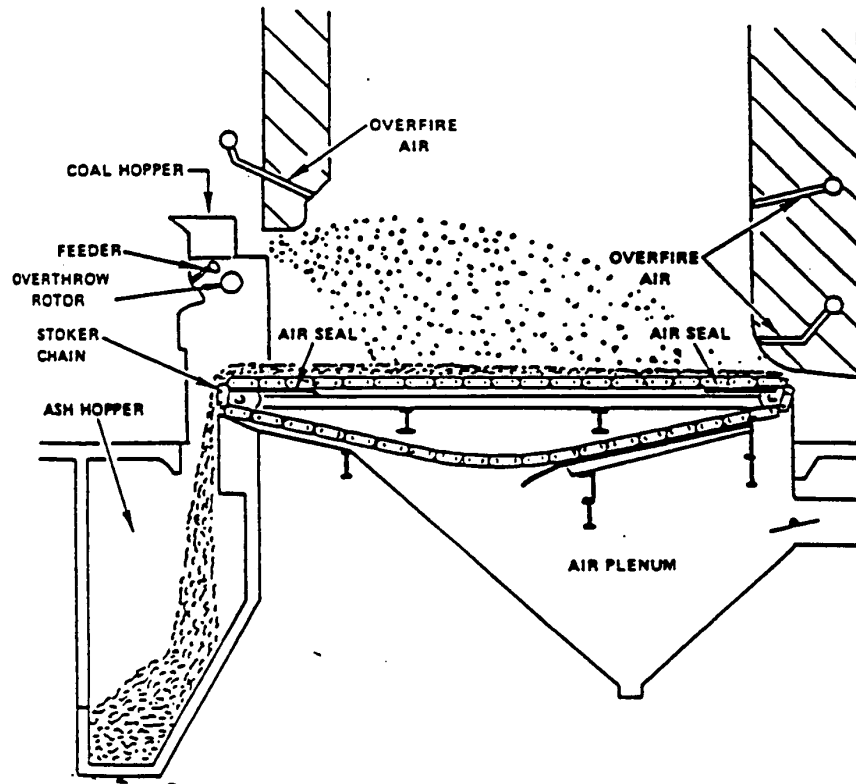
a/ pph = pounds steam/hr; 1 pph = 1000 Btu/hr.

b/ Maximum amount of Btus consumed per hour for each square foot of grate in
the stoker.

Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York,
NY, 1981.

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EXHIBIT 2-15
DIAGRAM OF A SPREADER STOKER



Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

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EXHIBIT 2-16

TOTAL COAL BOILER CAPACITY BY EPA REGION
(%)

<u>EPA Region</u>	<u>Pulverizers</u>		<u>Cyclone</u>	<u>Stoker</u>	<u>Other a/</u>	<u>Total</u>
	<u>Dry Bottom</u>	<u>Wet Bottom</u>				
1	69.2	11.3	16.7	0.0	2.8	100.0
2	60.6	19.4	5.0	2.7	12.2	100.0
3	87.6	0.3	2.8	0.0	9.2	100.0
4	71.6	5.3	5.2	0.1	17.7	100.0
5	70.4	4.9	14.0	0.5	10.1	100.0
6	48.6	12.5	0.0	0.0	38.9	100.0
7	58.3	3.5	19.2	1.0	18.0	100.0
8	60.3	5.4	10.6	1.1	22.5	100.0
9	77.5	0.0	0.0	0.0	22.5	100.0
10	<u>100.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>100.0</u>
U.S. Total	69.3	5.3	8.3	0.4	16.7	100.0

a/ Includes unknown, or other boiler types.

Source: ICF Coal and Utilities Information System Database.

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EXHIBIT 2-17

AVERAGE COAL BOILER SIZE BY TYPE OF BOILER
AND BY EPA REGION
(MW)

<u>EPA Region</u>	<u>Pulverizers</u>		<u>Cyclone</u>	<u>Stoker</u>
	<u>Dry Bottom</u>	<u>Wet Bottom</u>		
1	210.2	102.7	228.0	N/A
2	127.8	137.7	143.5	39.0
3	297.6	136.0	195.3	N/A
4	249.3	147.4	342.6	14.6
5	185.0	117.0	222.6	11.2
6	522.7	489.0	N/A	N/A
7	162.5	148.3	243.2	12.3
8	234.2	141.7	322.8	17.9
9	388.3	N/A	N/A	N/A
10	<u>610.0</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>
U.S. Total	231.8	162.9	243.2	14.0

N/A = Not applicable.

Source: ICF Coal and Utilities Information System Database.

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These impurities are typically referred to as "ash", whether the reference is to some of the constituents that compose the coal itself prior to combustion or the waste products that result from its combustion. Some coal ash is inherent to the coal seam, while other ash comes from non-coal strata near the coal seam which are intermixed during mining. The coal consumed by electric utilities is generally over 10 percent ash.²⁴ At current rates of coal consumption, about 70 million tons of ash pass through coal-fired power plants each year.²⁵

The ash generated at utility power plants is produced inside the boiler furnace from the inorganic components as the organic components of the coal combust. The types of ash produced can vary -- some ash is swept through the furnace with the hot flue gases to form fly ash, while some settles to the bottom of the boiler as bottom ash or slag. The amount of each type of ash produced depends upon the boiler configuration as described in Section 2.3 and the characteristics of the coal (see Chapter Three for further discussion of ash types).

Air quality regulations have long restricted the amount of fly ash that may be released through a power plant's stacks. Primarily through the use of electrostatic precipitators or bag houses, power plants collect fly ash particles, leaving the flue gases nearly particulate-free as they are emitted from the stack. As a result, the fly ash, bottom ash, and slag that is collected during and after combustion is approximately equal to the amount of ash in the coal prior to combustion.

2-35

For many power plants constructed since the 1970's, additional environmental controls also require that a portion of the sulfur oxides be removed from the flue gases. The dominant technology for removing sulfur oxides is known as flue gas desulfurization (FGD), in which alkaline agents, usually in liquid slurry form, are mixed with the flue gases to convert the sulfur into non-gaseous compounds. The resulting waste product is generally referred to as FGD sludge and can amount to 25 percent or more of the volume of coal consumed at a given plant.²⁶ In total, U.S. coal-fired power plants produce about 85 million tons of ash and FGD sludge per year. By the end of the century, this volume is expected to approximately double.

Exhibit 2-18 shows the number of coal-fired utility power plants and units that produce FGD wastes in each EPA region as of 1985. Regions 6, 8, and 9 have the highest proportion of both plants and units producing FGD wastes. For example, more than half of the coal-fired units in region 9 produce FGD wastes. The high proportion of FGD-producing plants in these regions is in part attributable to the fact that many of the coal-fired plants in these regions are relatively new and were required to incorporate scrubbers to meet air emission regulations.

Plants and units producing FGD waste represent a smaller percentage in other regions, primarily because these regions relied on coal-fired capacity for a major portion of their generation before units with FGD technology were installed. For example, the absolute number of both plants and units producing FGD waste is greatest in Region 4, reflecting this area's reliance on coal for generating electricity.

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EXHIBIT 2-18

ELECTRIC UTILITY PRODUCTION OF FGD WASTES: 1985

<u>EPA Region</u>	<u># of Plants Producing FGD waste</u>	<u>Percent of Plants Producing FGD Wastes</u>	<u># of Units Producing FGD Wastes</u>	<u>Percent of Units Producing FGD Wastes</u>
1	0	0.0	0	0.0
2	3	17.6	3	7.9
3	5	8.8	13	9.4
4	11	12.0	26	9.8
5	10	5.8	16	3.6
6	8	20.5	23	35.9
7	6	9.1	11	7.9
8	9	18.8	25	29.4
9	3	23.1	12	57.1
10	<u>0</u>	<u>0.0</u>	<u>0</u>	<u>0.0</u>
Total U.S.	55	12.0	129	14.4

Source: Utility Data Institute Power Statistics Database.

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Regions 1 and 10, at the other extreme, have no plants or units producing FGD wastes. These regions (New England and the Pacific Northwest) are not highly dependent upon coal and consequently, have relatively few coal-fired plants.

Numerous other types of wastes are produced during normal operation and maintenance at coal-fired power plants. These include, among others, boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. These wastes are usually small in volume relative to ash and FGD sludge, but because they may have higher concentrations of certain constituents that may cause environmental concern, they also require care in handling and disposal. All of these wastes are discussed in greater detail in Chapter Three.

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CHAPTER TWO

NOTES

- 1 Edison Electric Institute, 1985 Statistical Yearbook.
- 2 Energy Information Administration, Annual Energy Outlook 1985, DOE/EIA-0383(85), p. 50.
- 3 A gigwatt-hour (Gwh) is one million kilowatt-hours; a kilowatt-hour is the amount of electricity generated by 1 kilowatt of electric generating capacity operating for one hour.
- 4 Energy Information Administration, Annual Outlook for U.S. Electric Power, DOE/EIA-0474(86), 1986.
- 5 Ibid.
- 6 Ibid.
- 7 Ibid.
- 8 Ibid.
- 9 Ibid.
- 10 Ibid.
- 11 Ibid.
- 12 Ibid.
- 13 Ibid.
- 14 Ibid.
- 15 Ibid.
- 16 The major portion of this discussion is taken from Annual Outlook for U.S. Electric Power, DOE/EIA, 1986. See this document for further information.
- 17 Ibid., page 5.
- 18 Ibid.
- 19 Ibid.
- 20 Ibid.
- 21 Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 24.

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22 Energy Information Administration, Electric Power Monthly, DOE/EIA-0226(85/12), December 1985, p. 21.

23 For more detail, see Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, New York, 1981, pp. 378-431.

24 Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1984, DOE/EIA-0191(84), July 1985, p. 6.

25 American Coal Ash Association.

26 For example, a coal with 2 percent sulfur would produce approximately 80 pounds sulfur dioxide per ton of coal consumed. A limestone scrubber capturing 90 percent of the sulfur dioxide, assuming a stoichiometric ratio of 1.4 and a sludge moisture content of 50 percent, would product almost 500 pounds of FGD sludge per ton of coal consumed. See Appendix B for a detailed discussion of the methodologies used to determine this calculation.

CHAPTER THREE

WASTES GENERATED FROM COAL-FIRED ELECTRIC UTILITY POWER PLANTS

As part of EPA's responsibility under Section 8002(n) of RCRA, Congress directed that the study of wastes from the combustion of fossil fuels should include an analysis of "the source and volumes of such material generated per year." In response to this directive, this chapter examines the physical and chemical characteristics of the types and quantities of wastes that are generated currently and likely to be generated in the future.

3.1 OVERVIEW OF ELECTRIC UTILITY WASTES

As discussed initially in Chapter Two, the noncombustible material that remains after coal is burned is called ash. The proportion of noncombustible material in coal is referred to as the ash content. There are four basic types of wastes that can be produced directly from coal combustion: fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) sludge. The smaller ash particles entrained by the flue (exhaust) gas are referred to as fly ash and are produced in varying degrees by all plants. Larger ash particles that settle on the bottom of the boiler will form either bottom ash (if the particles have never completely melted) or boiler slag (if the ash particles have melted), depending on the furnace design. Another waste product, called FGD sludge, is generated when some of the sulfur dioxide (formed when the sulfur present in the coal combines with oxygen during combustion) is removed from other flue gases. This removal process is required by the Clean Air Act Amendments of 1979, which revised the New Source

3-2

Performance Standards for any electric utility boiler constructed after September 1978. These plants are required to remove 90 percent of the sulfur dioxide, which is usually accomplished with a flue gas desulfurization (FGD, or scrubber) system. Because they are generated in very large quantities, these four waste materials -- fly ash, bottom ash, boiler slag, and FGD sludge -- are referred to by the industry as high-volume wastes. This term will be used throughout this study to be consistent with the terminology that is commonly used for these wastes.

Electric utility power plants also generate waste streams that the industry typically calls low-volume wastes, which are formed during equipment maintenance and water purification processes. Types of low-volume wastes generated by coal-fired power plants include boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. Because it is common industry terminology, the term "low-volume wastes" will be used throughout this report; however, some of these wastes (such as cooling tower blowdown) can be generated in substantial quantities, although generally in smaller quantities than high-volume wastes.

The remainder of this chapter describes each type of high-volume and low-volume waste stream, the various methods of collection used for each, the volumes produced, and the physical and chemical characteristics that determine the waste's behavior during disposal and its potential to leach.

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3.2 HIGH-VOLUME WASTES

High-volume coal combustion utility wastes are those waste streams generated in the boiler furnace -- fly ash, bottom ash, and boiler slag -- and in the cleaning of coal combustion flue gas. The following sections describe the volumes and the physical and chemical characteristics of these high-volume waste streams.

3.2.1 Ash

The noncombustible waste material that remains after coal is burned is referred to as ash. Some noncombustible materials are characteristic of the coal itself, originating from the chemical elements in the plants from which the coal was formed. These materials generally account for no more than two percent of the ash content of the coal. Other noncombustible materials extraneous to the coal, such as minerals lodged in the coal seam during or after its geologic formation and rocks near the coal seam that are carried away with the coal during mining, are burned during the fuel combustion process along with the coal itself. These materials account for most of the ash content.

3.2.1.1 How Ash is Generated

The type of ash produced from a boiler is determined by the type of coal that is burned and the design of the boiler furnace. As discussed in Chapter Two, the major types of boilers used by electric utilities are wet-bottom pulverizers, dry-bottom pulverizers, cyclone-fired boilers, and stokers.

3-4

Pulverizers are the most widely used boilers in the electric utility industry because they can burn many different types of coal. Due to the very fine consistency of the coal after it is pulverized, the ash particles are easily carried out of the boiler along with the flue gases, resulting in a relatively large proportion of fly ash.

The amount of fly ash that accumulates in a pulverizer depends on whether it is dry-bottom or wet-bottom.¹ In dry-bottom pulverizers, which constitute the majority of electric utility boilers, ash particles in the coal generally do not melt during the combustion process because the ash fusion temperature (i.e., the melting point) is higher than the operating temperature in the boiler. In dry-bottom pulverizers, therefore, about 80 percent of the fine ash remains in the flue gas as fly ash. The remaining ash settles to the bottom of the boiler (hence the term bottom ash) where it is collected at a later time. In wet-bottom pulverizers, about 50 percent of the ash exits the boiler as fly ash, while the other 50 percent remains in the furnace. However, ash particles that remain in wet-bottom pulverizers become molten; this boiler slag remains in a molten state until it is drained from the boiler bottom.

Cyclone-fired boilers burn larger-sized coal particles than do pulverizers, since partial crushing is the only preparation required prior to injection into the furnace. The amount of fly ash that is generated in a cyclone boiler is less than that generated in a pulverizer because of the larger-sized coal particles and the design of the cyclone boiler. Because the air circulation within the boiler furnace is designed to create a cyclone-like

3-5

vortex, the coal particles have a tendency to contact the boiler walls. The operating temperature is high enough to melt the ash so that it adheres to the furnace walls as liquid slag. Excess slag continually drains to the bottom of the furnace, where it is removed for disposal. Only 20 to 30 percent of the ash formed in a cyclone boiler leaves the boiler as fly ash.

A few older and smaller power plants have stoker-type boilers, in which coal is burned on or immediately over a grate in the furnace. Stokers are designed to burn coals that do not contain too many small particles (fines), which can tend to smother the fire. Because there are fewer small particles, the amount of fly ash is reduced. For example, in a spreader stoker, the most common type of stoker boiler, the coal is uniformly fed over the fire in a manner that enables suspension burning of the finer pieces, while heavier pieces of coal fall onto the grate for further combustion. The large amount of coal that is burned on the grate reduces the amount of fly ash; the ash produced in a spreader stoker is generally about 50 percent fly ash and 50 percent bottom ash.

3.2.1.2 Methods of Ash Collection

As the flue gas leaves the boiler, it is passed through a mechanical ash collector to remove some of the fly ash particles. A mechanical ash collector operates by exerting centrifugal force on the fly ash particles, throwing them to the outside wall of the collector where they can be removed. These collectors are effective mainly for capturing the larger fly ash particles. To remove the smaller particles, the flue gas must then pass through some

3-6

other type of particulate control device, such as an electrostatic precipitator, a baghouse, or a wet scrubber.

The electrostatic precipitator (ESP) is the most common device for fine ash collection. ESPs operate by applying an electrical charge to the fly ash particles. In the presence of an intense electrical field, the charged particles are attracted to a grounded collection electrode. The collected dust is then discharged to a storage hopper by a process called rapping that dislodges the collected particles. ESPs are most efficient when coal with high sulfur content is used because the sulfur dioxide in the flue gas helps retain the electrical charge. When properly designed and maintained, an ESP is capable of collecting over 99 percent of the ash present in the flue gas.²

When coal with lower sulfur content is burned, baghouses (also called fabric filters) are often more appropriate to use as fly ash collection devices. If operated efficiently, they also can remove over 99 percent of the ash from the flue gas.³ In this system, the flue gas passes through a filter that traps the ash particles. The ash builds up on the filter, forming a filter cake. As this process continues, the ash collection efficiency tends to increase as it becomes more difficult for particles to pass through the filter material. Periodically, the cake is dislodged from the filters, which reduces efficiency until buildup occurs again.

Some power plants remove fly ash by the wet scrubbing method, in which liquids are used to collect the ash. In one method, the ash particles are removed from the flue gas stream by contacting them with a scrubbing liquid in a spray tower. This process forms an ash slurry, which is then discharged.

3-7

Alternatively, fly ash particles may be dislodged from the walls of the scrubber by a liquid flushing of the scrubber. Because the operation of a scrubber is very plant-specific, the collection efficiency of wet scrubbers varies, though wet scrubbers are generally not as efficient as ESPs and baghouses. The advantage of wet scrubbers, however, is that they can also be used simultaneously to collect sulfur oxides from the flue gas system.

Ash particles that do not escape as fly ash become bottom ash or boiler slag. In dry-bottom pulverizers and stokers, the temperatures are low enough to allow the molten ash to cool and reform into dry, solid ash particles, or bottom ash. In smaller boilers of this type, the ash falls onto a grate, which then is opened, allowing the ash to drop into a flat-bottom hopper. The large quantities of bottom ash produced in larger boilers often require hoppers with sloped sides for self-feeding. Some hoppers may contain water to quench the ash and to facilitate disposal.

In cyclone-fired boilers and wet-bottom pulverizers, the liquified ash particles that fall to the bottom of the boiler during combustion remain in a molten state and coalesce into large masses (called slag), which then drop onto the boiler floor. The slag is tapped into a water-filled hopper, or slag tank, which is periodically emptied and the slag disposed. Slag tanks for cyclone-fired boilers are similar to those used for pulverizers but have a higher relative capacity because a greater percentage of the ash in cyclones becomes boiler slag.

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3.2.1.3 Quantities of Ash Generated

Nearly all of the noncombustible material in coal ends up as fly ash, bottom ash, or boiler slag. As mentioned earlier, the coal industry and the electric utility industry refer to this material as a coal's ash content. As a result, the volume of ash generated is directly related to the amount of coal consumed and the ash content of the coal. The ash content of coal will vary according to several factors, including coal-producing region, coal rank (i.e., bituminous, subbituminous, anthracite, or lignite), mine, seam, and production method. Although the proportion of ash in coal may range from 3 to 30 percent, the industry-wide average for electric utility power plants is 10.1 percent.⁴ Exhibit 3-1 shows the average ash content of coal that was delivered to coal-fired power plants in 1985 for some of the major coal-producing regions.

In 1984, electric utilities generated about 69 million tons of coal ash. Ash generation is expected to increase considerably, to about 120 million tons in the year 2000, an increase of about 72 percent over 1984 levels. This increase can primarily be attributed to the increase in the demand for coal by electric utilities. While there is some uncertainty over the amount of coal that will be consumed by electric utility power plants, coal-fired electricity generation is likely to increase significantly. For example, one estimate indicates that by the year 2000 electric utility power plants will burn over one billion tons of coal to meet 61 percent of total electricity demand,⁵ an increase of 70 percent over the 664 million tons consumed in 1984.⁶ Exhibit 3-2 shows historical and forecasted future ash generation by coal-fired electric power plants.

3-9

EXHIBIT 3-1

REPRESENTATIVE ASH CONTENTS BY PRODUCING
REGION AND COAL RANK: 1985

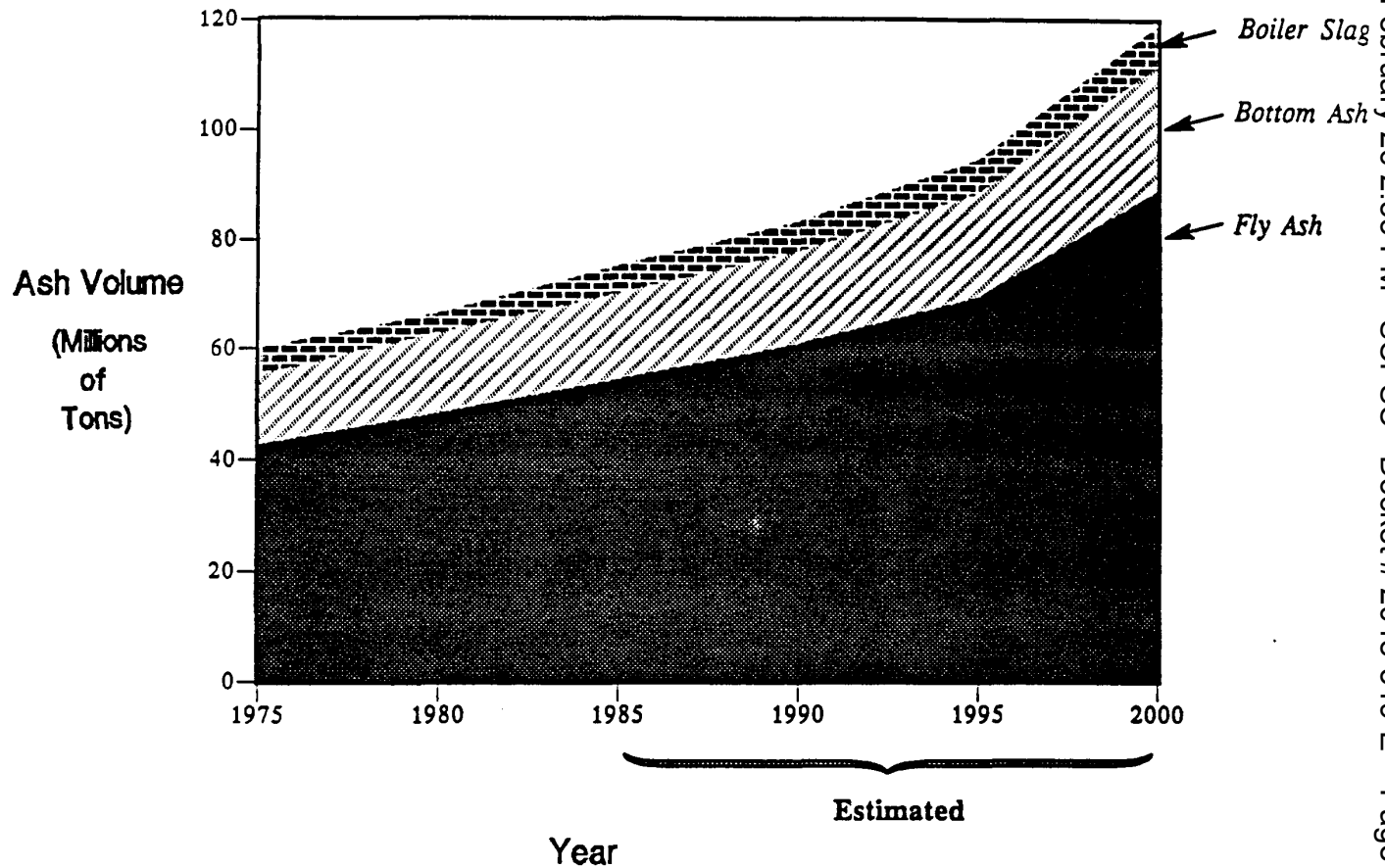
<u>Coal Rank and Region</u>	<u>Percent Ash</u>
<u>Anthracite</u>	
Northeastern Pennsylvania	29.4
<u>Bituminous</u>	
Western Pennsylvania	10.9
Northern West Virginia	10.4
Ohio	11.3
Eastern Kentucky	9.9
Alabama	12.2
Illinois	9.7
Colorado	6.2
Utah	9.4
Arizona	8.9
<u>Subbituminous</u>	
Wyoming	5.9
New Mexico	18.8
<u>Lignite</u>	
Texas	15.8
North Dakota	<u>9.0</u>
U.S. Average	10.1

Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(85), July 1986.

3-10

EXHIBIT 3-2

VOLUME OF ASH GENERATED BY COAL-FIRED
ELECTRIC UTILITY POWER PLANTS
1975 - 2000



Sources: 1975-1984: American Coal Ash Association.
1985-2000: ICF Incorporated. See Appendix B for in-depth
discussion of the methodologies used to develop these estimates.

3-11

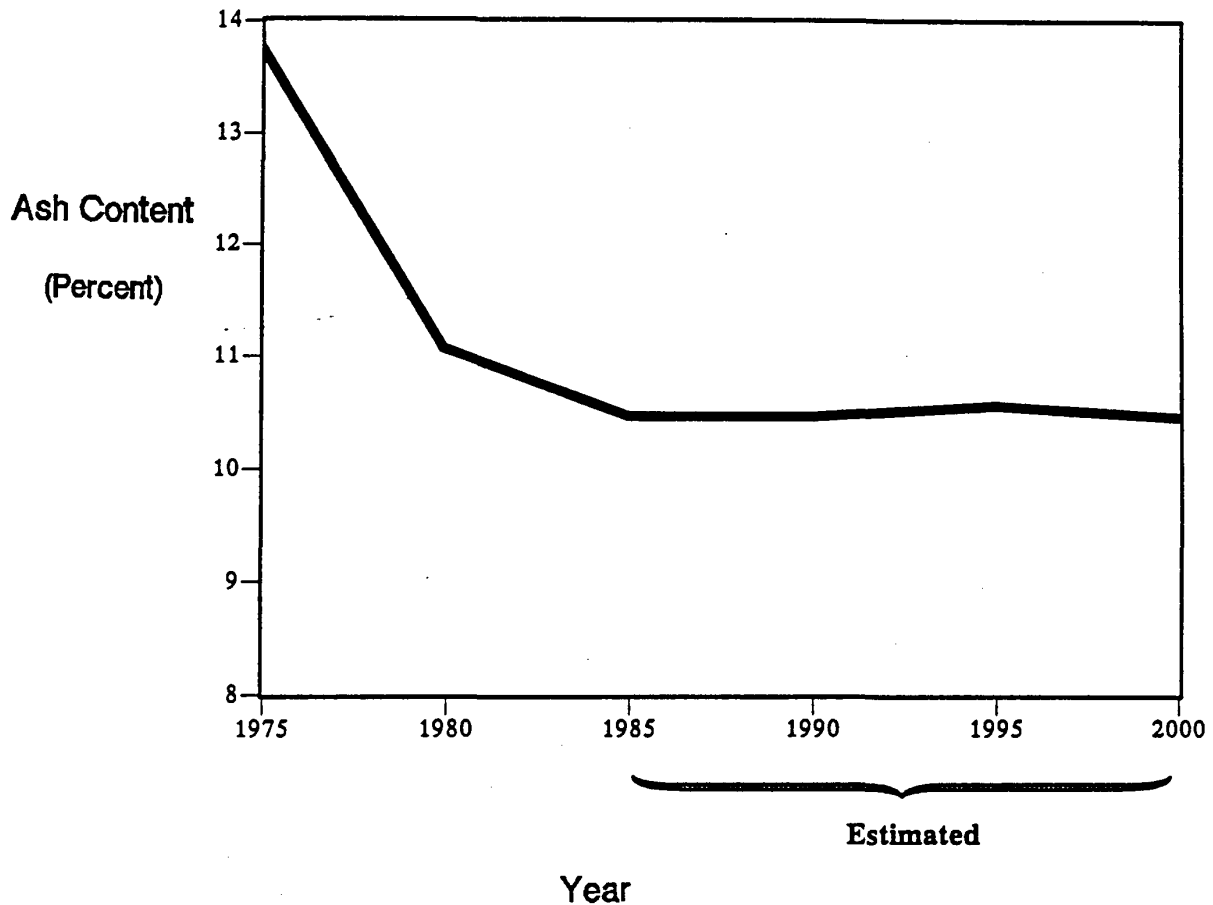
The average ash content of coal burned by electric utilities has declined from about 14 percent to slightly more than 10 percent over the past decade (see Exhibit 3-3). To meet particulate emission standards and to lower certain operating and maintenance costs, more electric utilities are now choosing to burn coal with lower ash contents. Although some coals are naturally low in ash, producers and/or utilities can also reduce ash content by cleaning the coal.⁷ In some cases, cleaning can reduce ash content by as much as 50 to 70 percent. At present, utilities clean about 35 percent of all the coal they consume; most of the coal that is cleaned comes from eastern and midwestern underground bituminous coal-mining operations. Another reason for the increased use of coal with lower average ash content is the growth in Western coal production, particularly in the Powder River Basin area of Montana and Wyoming. These coals are naturally low in ash content, and little ash is extracted during the mining process.

The quantity of fly ash and bottom ash produced is likely to increase faster over time than the quantity of boiler slag because most new coal-fired plants will employ dry-bottom pulverizer boilers, which generate fly ash and bottom ash rather than boiler slag. Because dry-bottom pulverizers are capable of burning coal with a wide range of ash fusion temperatures,⁸ they are able to burn a greater variety of coals compared with cyclone boilers and wet-bottom pulverizers. Another advantage of dry-bottom pulverizers is that they produce less nitrogen oxide emissions than do other boiler types, which enables electric utilities to meet requirements for nitrogen oxide emissions control more easily.

3-12

EXHIBIT 3-3

**AVERAGE ASH CONTENT OF COAL BURNED
BY ELECTRIC UTILITY POWER PLANTS IN THE U.S.
1975 - 2000**



Source: 1975-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants.
1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

3.2.1.4 Physical Characteristics of Ash

The physical characteristics of coal combustion ash of interest are particle size and distribution, compaction behavior, permeability, and shear strength. Exhibit 3-4 provides representative ranges of values for these characteristics of fly ash, bottom ash, and boiler slag.

The greater the assortment of particle sizes in the material, the more it can be compacted to achieve greater density and shear strength and lower permeability. Generally, fly ash is similar in size to silt. Most fly ash particles are between 5 and 100 microns in diameter; within a single sample, the largest particles may be 200 times larger than the smallest particles.⁹ The size of bottom ash and boiler slag particles can range from that of fine sand to fine gravel, or about 0.1 to 10 millimeters.¹⁰

Compaction behavior refers to the amount of settling that takes place after disposal and the rate at which such settling occurs. Compressibility, density, and moisture content are factors affecting compaction behavior.¹¹ When compacted and dry, most fly ash and bottom ash behave very similarly to cohesive soil.

Permeability reflects the rate at which water will seep through the waste material in a given period of time and provides a good first estimate of the rate and quantity of leachate migration. A number of factors can influence the degree of permeability, such as the size and shape of the waste particles, the degree of compaction, and the viscosity of the water. Properly compacted fly ash often has low permeability, similar to that of clay, while the

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EXHIBIT 3-4

REPRESENTATIVE RANGES OF VALUES
FOR THE PHYSICAL CHARACTERISTICS OF
FLY ASH, BOTTOM ASH, AND BOILER SLAG

	<u>Fly Ash</u>	<u>Bottom Ash/ Boiler Slag</u>
Particle Size (mm)	0.001-0.1	0.1-10
Compaction Behavior:		
Compressibility (%)	1.8	1.4
Dry Density (lbs/ft ³)	80-90	80-90
Permeability (cm/sec)	10 ⁻⁶ -10 ⁻⁴	10 ⁻³ -10 ⁻¹
Shear Strength		
Cohesion (psi)	0-170	0
Angle of Internal Friction (°)	25-45	25-45

Sources: For compressibility values, Arthur D. Little, Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Volume I, Prepared for U.S. Environmental Protection Agency, June 1985, p. 3-29. For other values, Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 3-3 - 3-8.

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permeability of bottom ash is usually slightly higher. Boiler slag is higher still, having a permeability comparable to that of fine gravel.

Shear strength is an important determinant of the shape and structural stability of wastes disposed in landfills; a strong material (i.e., one with high shear strength) can form steep slopes and support heavy loads from above. Two indicators of shear strength are cohesion, a measure of the attraction between particles due to electrostatic forces, and the angle of internal friction, an indicator of the friction between particles. Dry, nonalkaline ash has no cohesion. Dry ash that is alkaline demonstrates some cohesion and, when compacted, increases in strength over time. The angle of internal friction associated with ash varies with the degree of compaction, although it is similar to that for clean, graded sand.

3.2.1.5 Chemical Characteristics of Ash

The chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very plant- and coal-specific.

In general, over 95 percent of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms. Magnesium, potassium, sodium, and titanium are also present to a lesser degree. Exhibit 3-5 shows the concentration of these major elements typically found in fly ash, bottom ash, and boiler slag.

Ash also contains many other elements in much smaller quantities. The types and proportions of these trace elements are highly variable and not

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EXHIBIT 3-5

LOW AND HIGH CONCENTRATIONS OF MAJOR CHEMICAL
CONSTITUENTS FOUND IN ASH GENERATED
BY COAL-FIRED POWER PLANTS
(parts per million)

	<u>Fly Ash</u>		<u>Bottom Ash/Boiler Slag</u>	
	<u>Low</u>	<u>High</u>	<u>Low</u>	<u>High</u>
Aluminum	11,500	144,000	88,000	135,000
Calcium	5,400	177,100	8,400	50,600
Iron	7,800	289,000	27,000	203,000
Magnesium	4,900	60,800	4,500	32,500
Potassium	1,534	34,700	7,300	15,800
Silicon	196,000	271,000	180,000	273,000
Sodium	1,180	20,300	1,800	13,100
Titanium	400	15,900	3,300	7,210

Source: Utility Solid Waste Activities Group, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix A, Submitted to the U.S. Environmental Protection Agency, October 26, 1982, p. 31.

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readily categorized. Concentrations for various trace elements in coal ash are shown in Exhibit 3-6, which indicates the potential range of values and median concentration for such trace elements for coals from different regions of the U.S. A summary of how the concentration of elements in ash varies according to coal source is shown in Exhibit 3-7. For example, Eastern and Midwestern coal ashes usually contain greater amounts of arsenic, selenium, chromium, and vanadium than do Western coal ashes, while Western coals have larger proportions of barium and strontium. Coal mining and cleaning techniques can reduce the amount of trace elements that are ultimately found in the ash after combustion. For example, in some cases, coal cleaning can remove more than half of the sulfur, arsenic, lead, manganese, mercury, and selenium that is contained in the coal prior to combustion.

The proportions of elements contained in fly ash, bottom ash, and boiler slag can vary. Exhibit 3-8 provides ranges and median values for element concentrations in different types of ash -- bottom ash and/or boiler slag, and fly ash. The concentrations of elements formed in fly ash are shown for two types -- the larger particles removed from the flue gas by mechanical collection and the smaller particles removed with an electrostatic precipitator or a baghouse (see Section 3.2.1.2 for more detail on methods of ash collection). For example, much higher quantities of arsenic, copper, and selenium are found in fly ash than are found in bottom ash or boiler slag. The distribution of elements among the different types of ash is largely determined by the firing temperature of the boiler relative to the coal's ash fusion temperature, which in turn affects the proportions of volatile elements that end up in fly ash and bottom ash. Some elements, such as sulfur, mercury, and chlorine, are almost completely volatilized and leave the boiler

EXHIBIT 3-6

ELEMENT CONCENTRATIONS IN ASH FROM THREE GEOGRAPHIC SOURCES
(milligrams per kilogram)*

Element	Eastern Coal		Midwestern Coal		Western Coal	
	Range	Median	Range	Median	Range	Median
Arsenic	2.0-279	75	0.50-179	54	1.3-129	18
Barium	52-2200	892	300-4300	905	300-5789	2700
Boron	10.0-580	121	10-1300	870	41.9-1040	311
Cadmium	0.10-8.24	1.59	0.50-18	2.6	0.10-14.3	1.01
Chromium	34-437	165	70-395	172	3.4-265	45
Cobalt	6.22-79	40.6	19-70	35.7	4.9-69	13.0
Copper	3.7-349	136	20-330	125	29-340	74.8
Fluorine	0.40-89	8.8	3.2-300	75	0.40-320	50.1
Lead	1.3-222	18.0	3.0-252	149	0.40-250	26.1
Manganese	79-430	190	194-700	410	56.7-769	194
Mercury	0.02-4.2	0.192	0.005-0.30	0.044	0.005-2.5	0.067
Molybdenum	0.84-51	15.0	7.0-70	43	1.4-100	12.0
Nickel	6.6-258	78	26-253	121	1.8-229	38.0
Selenium	0.36-19.0	8.05	0.08-19	7.0	0.13-19.0	4.1
Silver	0.25-8.0	0.695	0.10-1.20	0.39	0.040-6.0	0.26
Strontium	59-2901	801	30-2240	423	931-3855	2300
Thallium	7.0-28.0	25.0	2.0-42	16.0	0.10-3.50	1.06
Vanadium	110-551	269	100-570	270	11.9-340	94
Zinc	16-1420	163	20-2300	600	4.0-854	71

* Values shown are for all types of ash combined.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983.

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EXHIBIT 3-7

EFFECT OF GEOGRAPHIC COAL SOURCE ON ASH ELEMENT CONCENTRATION

<u>Element</u>	<u>Concentration Pattern</u>
Arsenic	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	greater in eastern than in midwestern coal ash; greater still in western coal ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	greater in eastern than in western coal ash; greater still in midwestern coal ash

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-30.

EXHIBIT 3-8

ELEMENT CONCENTRATIONS IN THREE TYPES OF ASH
(milligrams per kilogram)

Element	Bottom Ash/Boiler Slag		Fly Ash		Fine Fly Ash	
	Range	Median	Mechanical Hopper Ash Range	Median	Range	Median
Silver	0.1-.51	0.20	0.08-4.0	0.70	0.04-8.0	0.501
Arsenic	.50-168	4.45	3.3-160	25.2	2.3-279	56.7
Boron	41.9-513	161	205-714	258	10.0-1300	371
Barium	300-5789	1600	52-1152	872	110-5400	991
Cadmium	0.1-4.7	0.86	0.40-14.3	4.27	0.10-18.0	1.60
Cobalt	7.1-60.4	24	6.22-76.9	48.3	4.90-79.0	35.9
Chromium	3.4-350	120	83.3-305	172	3.6-437	136
Copper	3.7-250	68.1	42.0-326	130	33.0-349	116
Fluorine	2.5-104	50.0	2.50-83.3	41.8	0.40-320	29.0
Mercury	0.005-4.2	0.023	0.008-3.00	0.073	0.005-2.50	0.10
Manganese	56.7-769	297	123-430	191	24.5-750	250
Lead	0.4-90.6	7.1	5.2-101	13.0	3.10-252	66.5
Selenium	.08-14	0.601	0.13-11.8	5.52	0.60-19.0	9.97
Strontium	170-1800	800	396-2430	931	30.0-3855	775
Vanadium	12.0-377	141	100-377	251	11.9-570	248
Zinc	4.0-798	99.6	56.7-215	155	14.0-2300	210

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Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-24.

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in the flue gas rather than remaining in the bottom ash or boiler slag. Some of these more volatile elements may condense on the surface of the fly ash particles as the flue gas cools.

3.2.2 FGD Sludge

Another waste stream often generated in large volumes by coal-fired utility power plants is FGD sludge, which is created when utilities remove sulfur oxides from the flue gases. Emissions of sulfur oxides in the flue gases are due to the oxidation of sulfur during coal combustion. State and Federal regulations require power plants to control the amount of sulfur oxides released through the stack. To meet the applicable requirements most power plants use coals whose inherent sulfur content is low. If the sulfur content is so low that additional sulfur dioxide removal is not needed, then FGD sludge is not produced.

Present requirements for all new coal-fired plants, however, not only limit the amount of sulfur oxides that can be emitted, but also mandate a percentage reduction in the amount of sulfur dioxide emissions.¹² This requirement will substantially increase the number of sulfur dioxide control systems in use. The primary method of sulfur dioxide control currently available is a flue gas desulfurization (FGD) system through which the flue gases pass before being emitted from the stack. The wastes produced by this system are called FGD (scrubber) sludge. Other methods of control include newer technologies such as fluidized bed combustion (FBC) and limestone injection multistage burners (LIMB).¹³ The technical and economic feasibility of the latter two technologies are currently under evaluation by private industry and the U.S.

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Department of Energy. If these technologies do become more widely available, they also will produce substantial volumes of wastes.

3.2.2.1 Methods of FGD Sludge Collection

There are two major types of FGD (scrubber) systems. Non-recovery systems produce a waste material for disposal. Recovery systems produce recyclable by-products. Exhibit 3-9 illustrates the different types of FGD systems currently in use. Non-recovery systems, which account for 95 percent of the scrubber systems now in use by electric utilities, are further classified as wet or dry systems. In wet non-recovery scrubber systems, the flue gas contacts an aqueous solution of absorbents, thereby producing waste in a slurry form. The wastes generated by dry non-recovery systems contain no liquids.

Direct lime and limestone FGD systems are the most common wet non-recovery processes. With these systems, flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone in the form of a slurry. The slurry circulates between the contact chamber and a separate reaction tank, where the reagents are added. From the reaction tank, the slurry is fed to a thickening and dewatering device to be prepared for disposal. After dewatering, the resulting liquid is recycled back to the reaction tank and the sludge solids are removed for disposal. Under certain conditions, direct lime and limestone scrubbers have been able to remove over 95 percent of the sulfur dioxide in the flue gas.¹⁴

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EXHIBIT 3-9

MAJOR TYPES OF FLUE GAS DESULFURIZATION SYSTEMS

Non-Recovery		Recovery	
Wet	Dry	Wet	Dry
Direct Lime	Spray Drying	Wellman-Lord	Alumina/Copper* Sorbent
Direct Limestone	Dry Sorbent Injection*	Magnesium Oxide	Activated Carbon* Sorbent
Alkaline Fly Ash			
Dual-Alkali			

*Systems are currently in development and testing phases, and are not as yet being used commercially.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-1 - 4-4.

3-24

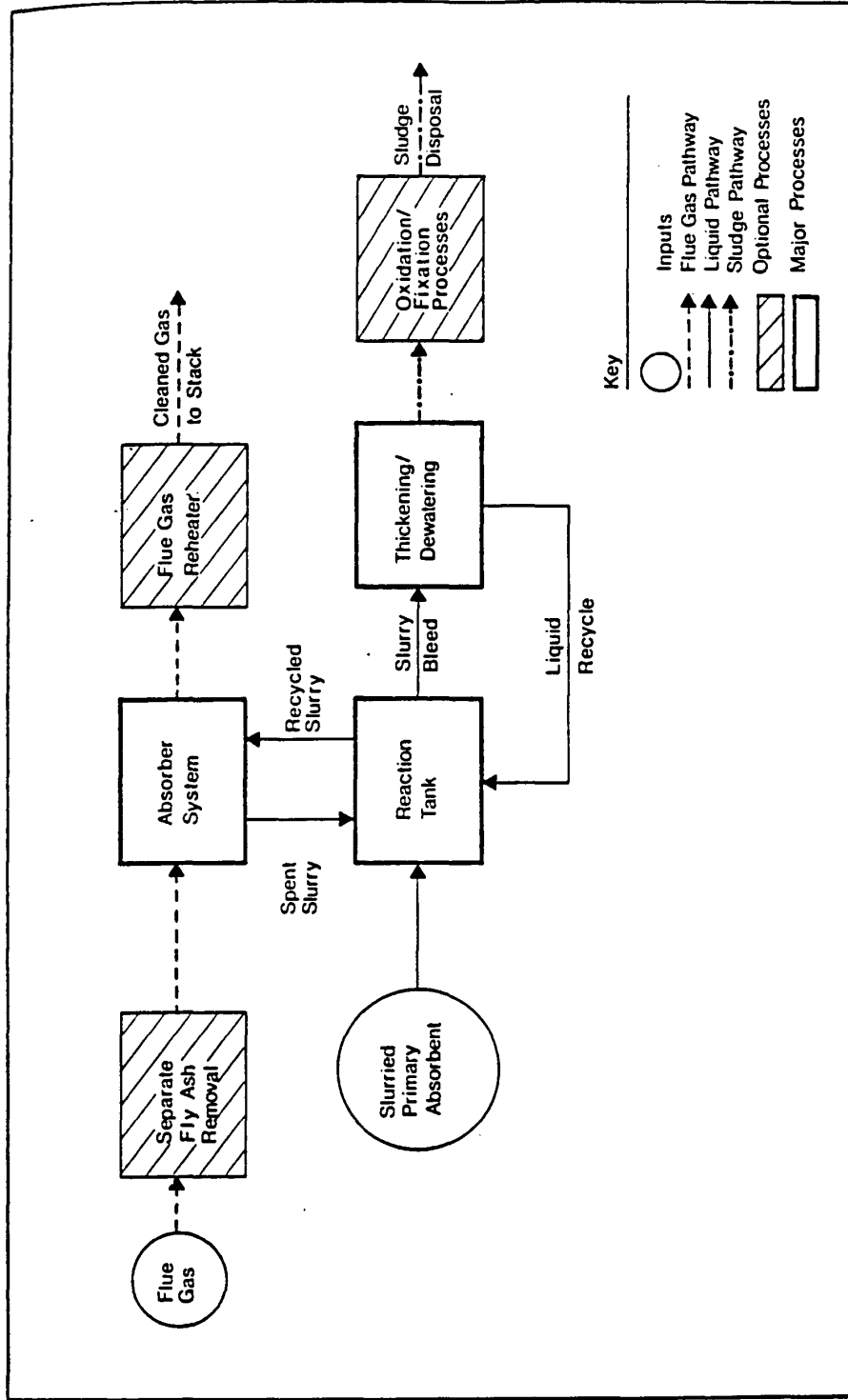
A variation on the direct lime and limestone systems is the alkaline fly ash scrubber. Several western power plants that burn coal containing high-alkaline ash use these systems, which can improve sulfur dioxide removal. Rather than being collected by a separate upstream device (such as an ESP or baghouse), fly ash particles remain in the gas stream as it passes through the scrubber. In the scrubber, the alkaline fly ash, augmented with an alkaline lime/limestone slurry, acts to remove sulfur oxides. Alkaline fly ash scrubbers are not as efficient as direct lime and limestone systems, removing on average only about 40 percent of the sulfur dioxide.¹⁵

Another wet non-recovery system is the dual-alkali process. These scrubbers operate in much the same manner as the direct lime and limestone scrubbers. However, dual-alkali systems use a solution of sodium salts as the primary reagent to which lime is added for additional absorption. The soluble sodium salts are then recycled to the scrubber system and the insoluble portion of the slurry is left to settle so that it can be collected and disposed. Like direct lime and limestone systems, dual-alkali scrubbers remove up to 95 percent of the sulfur dioxide.¹⁶

Exhibit 3-10 presents a diagram of the operations of a wet FGD system. The flows shown for the flue gas, absorbent, slurry, and sludge are essentially the same for direct lime, direct limestone, alkaline fly ash, and dual-alkali systems.

At present, the two most popular methods of dry scrubbing under investigation are spray-drying and dry sorbent injection, although only the spray-drying process is now in commercial use at electric utility power plants.

EXHIBIT 3-10
FLOW DIAGRAM OF WET FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-3.

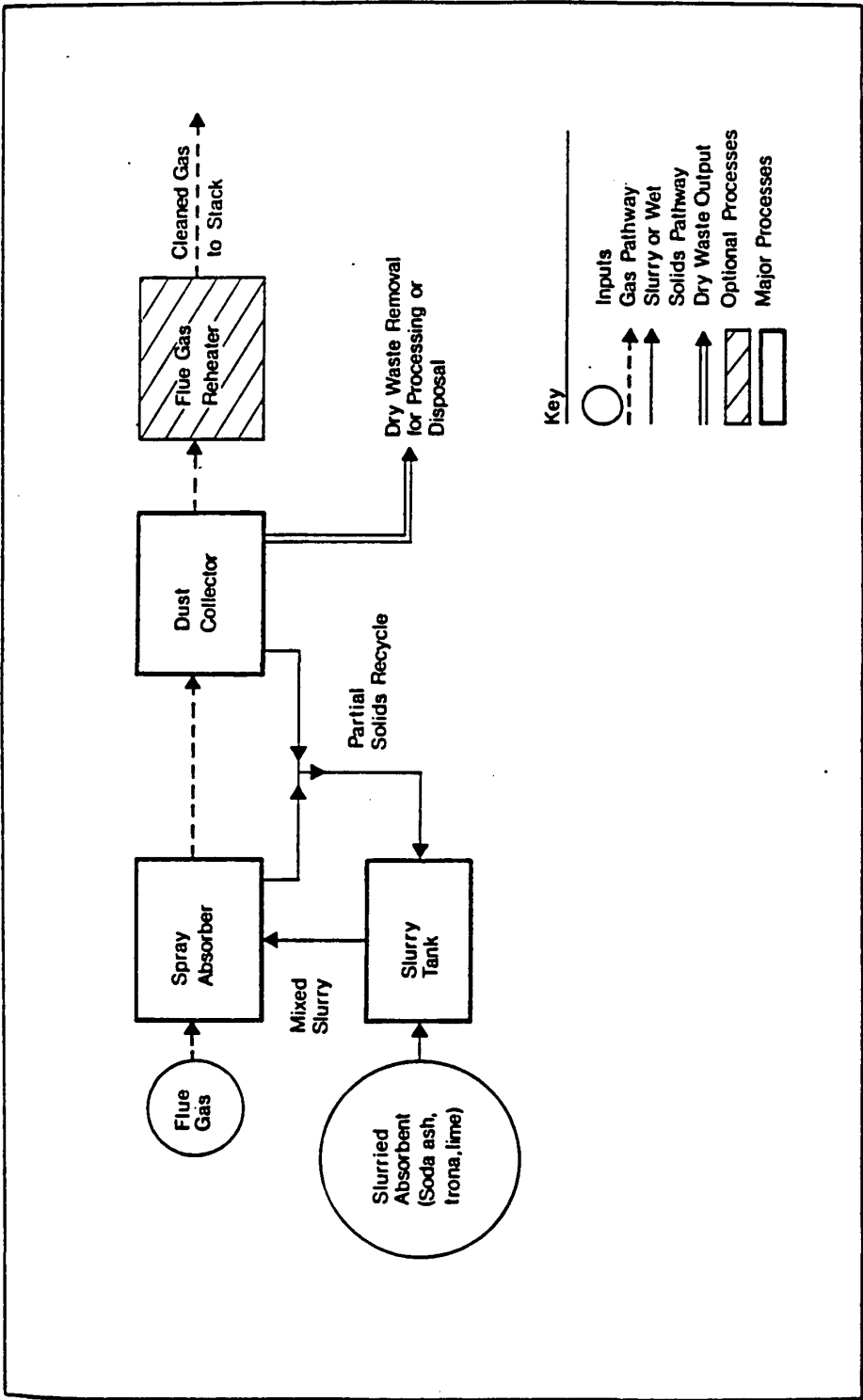
3-26

A flow diagram of a spray-drying system is presented in Exhibit 3-11. With this system, a fine spray of an alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water from the absorbent solution, leaving a dry powder. This powder is then collected downstream of the contact chamber by a particulate collector, usually a baghouse. Spray-drying typically removes about 70 percent of the sulfur dioxide from the flue gas.¹⁷ Because of the relatively low percentage reduction in sulfur dioxide achieved by spray-drying scrubbers compared with other scrubber technologies, this dry-scrubbing method is most commonly used for furnaces that burn lower sulfur coals.

Dry sorbent injection, illustrated schematically in Exhibit 3-12, is not yet used commercially by electric utilities, although one utility is designing a generating unit that will use this type of scrubber and which is due to begin operation by 1990.¹⁸ This system involves the injection of a powdered sorbent, either nacholite or trona, into the flue gas upstream of a baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse. The dry wastes, which form a filter cake, are then removed during normal filter cleaning.

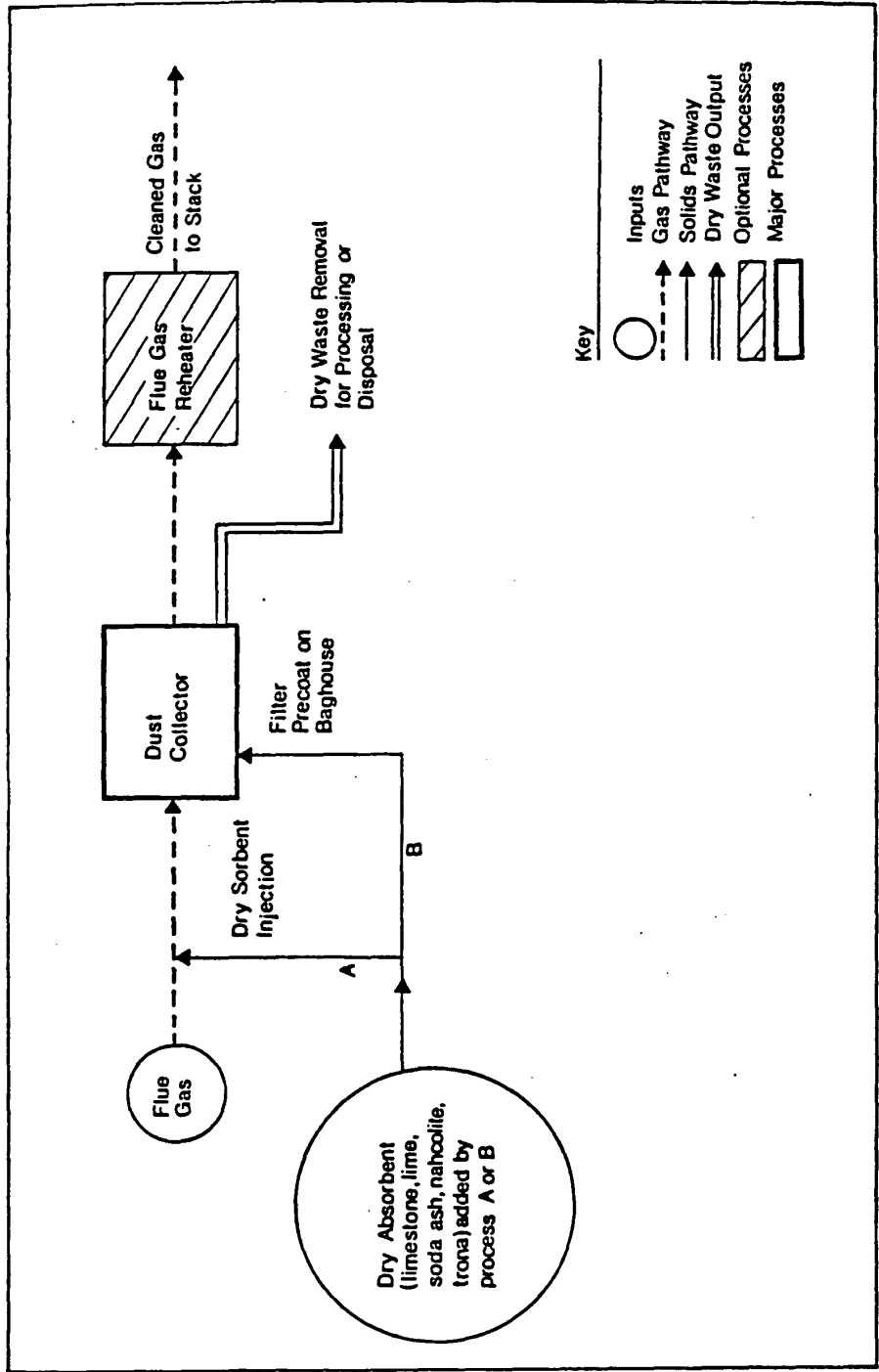
Dry injection offers several advantages over traditional wet scrubbing and spray-drying techniques: the required equipment is smaller and less expensive, no water is needed, flue gas reheating is not necessary, and sulfur dioxide and fly ash are removed simultaneously. Potential drawbacks of this process are the limited geographic availability of the sorbents and problems associated with waste disposal. For example, the waste tends to be very water soluble,

EXHIBIT 3-11
FLOW DIAGRAM OF SPRAY-DRYING FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-5.

EXHIBIT 3-12
FLOW DIAGRAM OF DRY INJECTION FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-6.

3-29

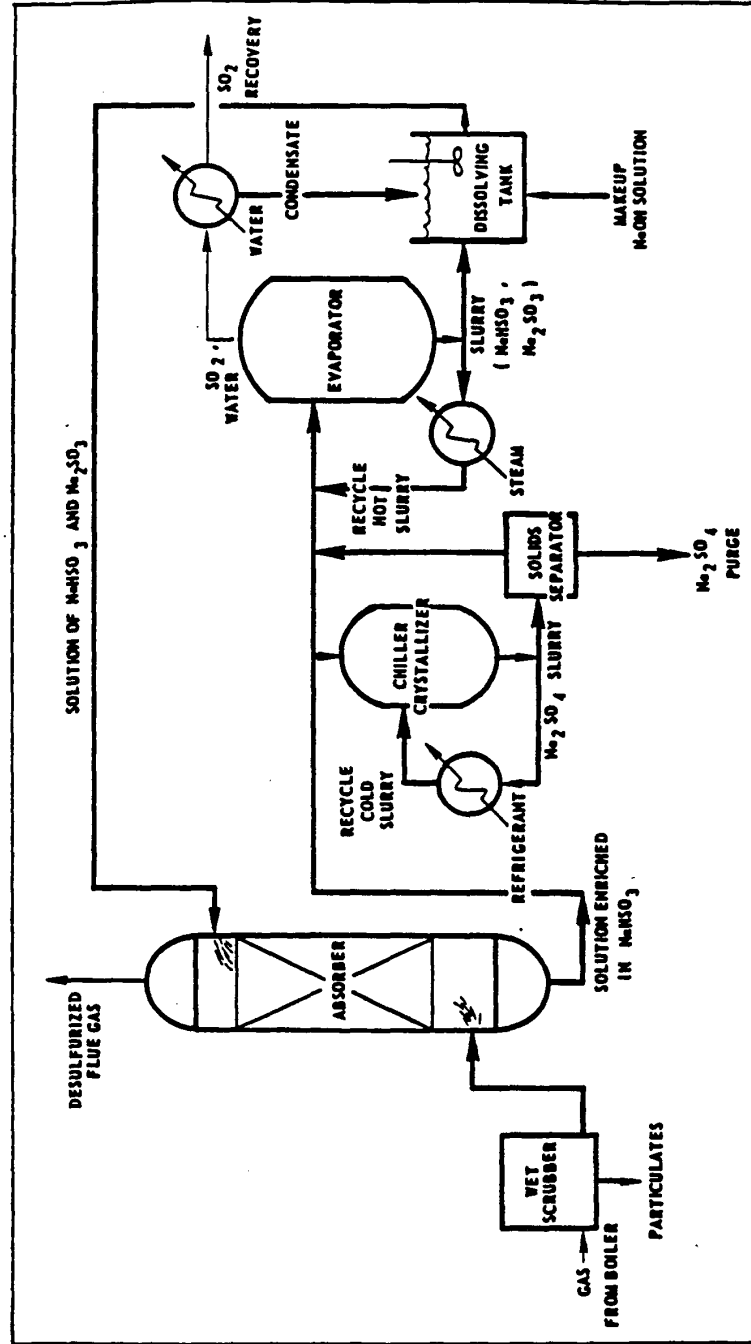
and could potentially affect ground-water quality. Also, dry injection is most effective when used for low-sulfur coals, achieving only 70 to 80 percent sulfur dioxide removal in most cases, compared with up to 95 percent removal by wet scrubbing systems.¹⁹

Recovery systems are designed to produce a salable by-product such as sulfur, sulfuric acid, or liquid sulfur dioxide; however, small amounts of waste are still produced. A prescrubber is usually required upstream of the main scrubber to filter out such contaminants as fly ash and chlorides. Secondary waste streams formed by the oxidation of the absorbent are sometimes present and, along with the prescrubber by-products, are the materials that need to be disposed. Two recovery FGD systems presently used commercially, the Wellman-Lord and Magnesium Oxide processes, are both based on wet scrubbing. Diagrams of these systems are shown in Exhibit 3-13. Other recovery systems, both wet and dry, have been developed, but are still in the testing phase.

3.2.2.2 Quantities of FGD Sludge Generated

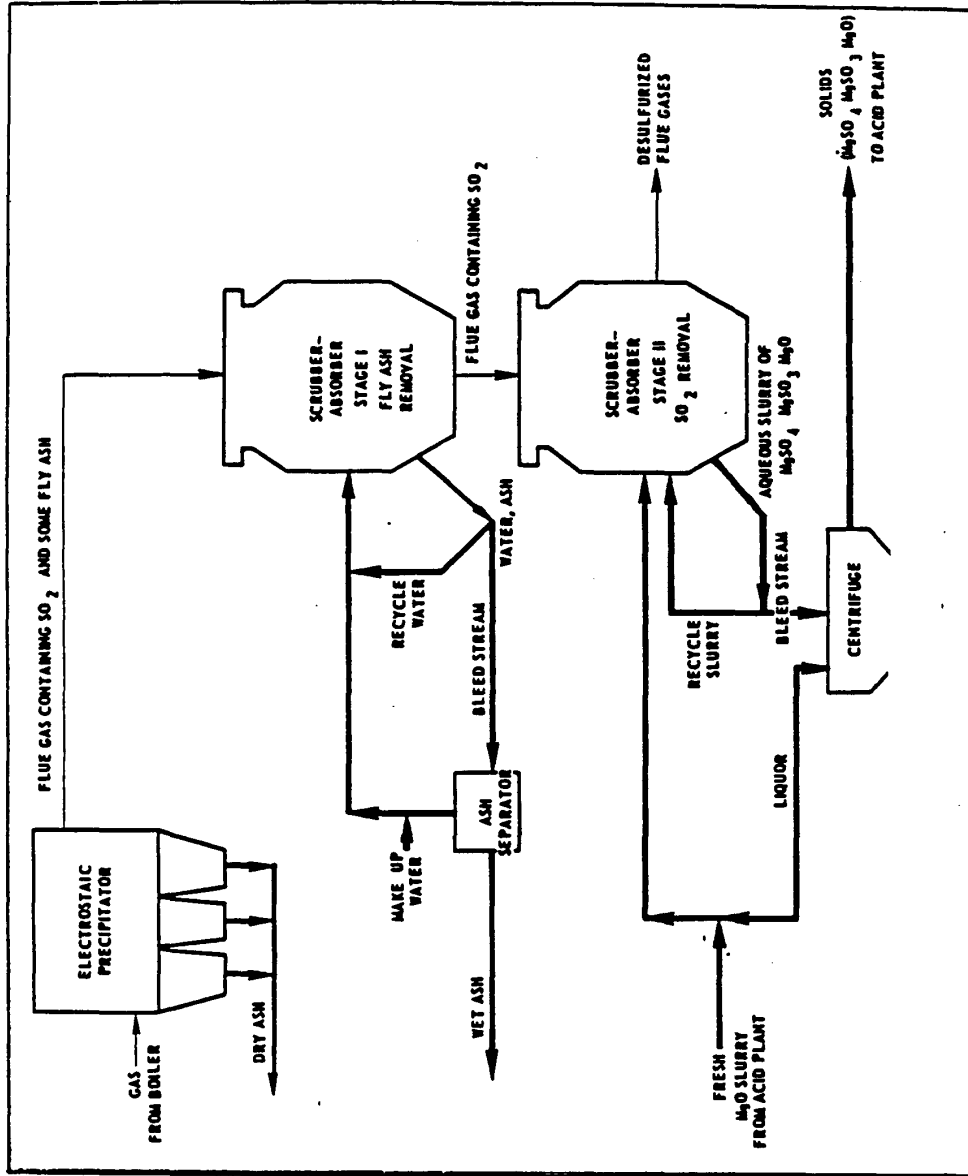
There has been a large increase in the quantity of FGD sludge generated over the past decade, as shown in Exhibit 3-14. This increase is due to the more widespread use of scrubbers brought about by tightened state limits on sulfur dioxide emissions, the Federal New Source Performance Standards (NSPS) of the Clean Air Act of 1971, and the revisions to the NSPS in 1979. This trend will continue as new power plants are equipped with scrubbers as required under the NSPS. By the year 2000, scrubber capacity is likely to be several times greater than at present.

EXHIBIT 3-13
FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS
WELLMAN-LORD PROCESS



Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

EXHIBIT 3-13 (Continued)
FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS
MAGNESIUM OXIDE PROCESS

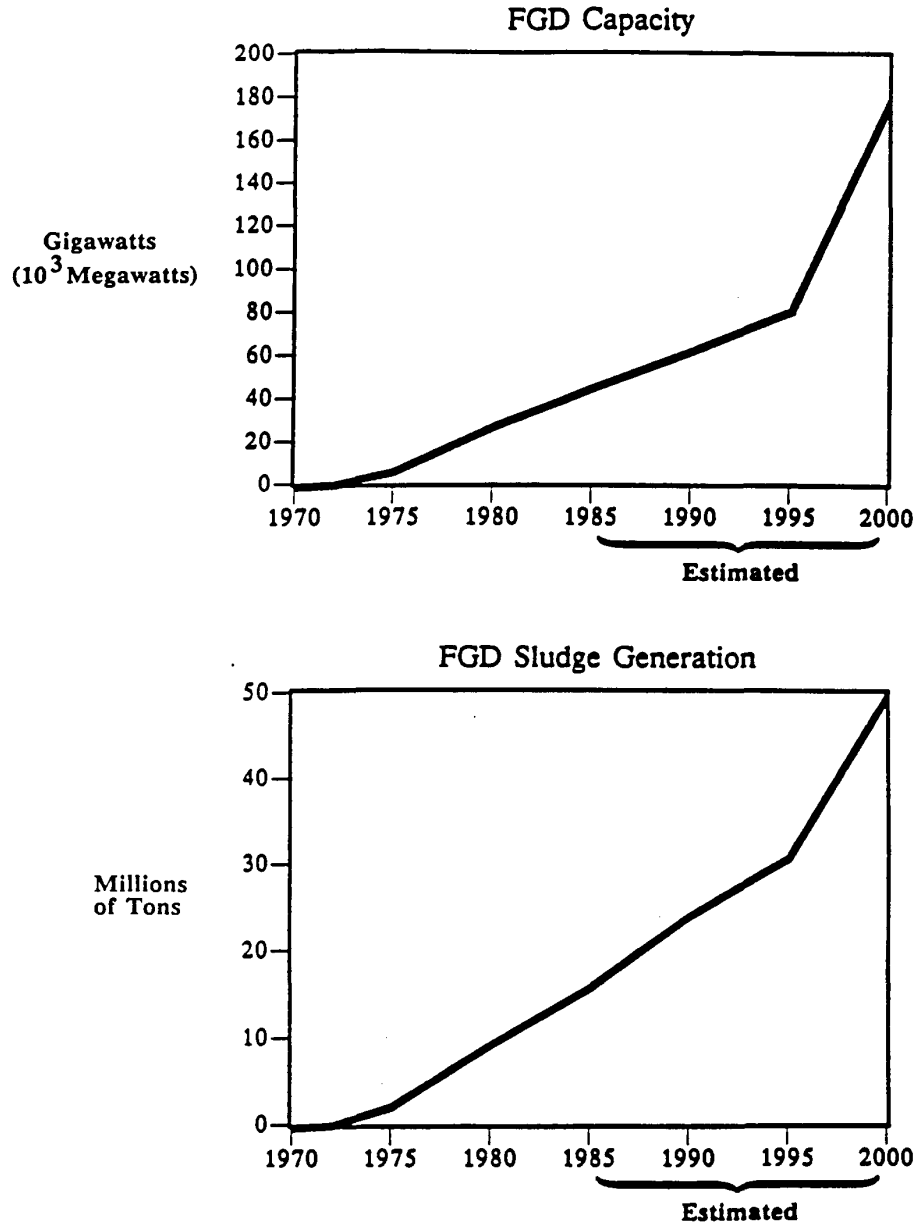


Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

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EXHIBIT 3-14

FGD CAPACITY AND FGD SLUDGE GENERATION
1970-2000



Source: 1970-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants, and Arthur D. Little, Inc., Full Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Vol. 1, June 1985.

1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

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The dramatic increase in scrubber capacity has a direct effect on the amount of scrubber sludge produced. In 1984, about 16 million tons of scrubber sludge were generated. By 2000, the annual amount of sludge produced is estimated to be about 50 million tons, over three times the sludge generated at present.²⁰

All FGD sludge is comprised of spent reagent, which is made up of the chemicals that result from the reaction of the absorbent with the sulfur oxides in the flue gas, plus any unreacted portion of the absorbent. The sludge may also contain water and fly ash. Several factors determine how much spent reagent, water, and ash are present in the FGD sludge. These factors include the type of scrubber system used, the characteristics of the coal, and the sulfur dioxide emission limit that the power plant is required to meet by state or Federal law.

The type of FGD system is an important determinant of the amount of spent reagent, amount of water, and amount of ash present in the sludge. Reagents used in different systems vary as to their absorbent utilization, or "stoichiometry," which is the percentage of the reagent that reacts with the sulfur oxides. A lower percentage implies more reagent is needed to remove a given percentage of sulfur dioxide. Direct limestone systems have an average absorbent utilization of 80 percent, while the direct lime and dual-alkali processes both achieve higher utilization of 90 and 95 percent, respectively. This results in the generation of about six percent more sludge by direct limestone scrubbers compared to direct lime and dual-alkali processes.²¹

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Wet systems, both non-recovery and recovery, employ aqueous solutions to remove the sulfur oxides from the flue gas. Dry FGD systems use no water for sulfur oxide removal, although dry FGD wastes may be mixed with water prior to disposal, which increases the volume of sludge. Because of their dependency on water, wet FGD systems generally produce larger volumes of wastes than do dry systems.

Wet FGD systems can also be used as fly ash removal devices. The amount of ash in the sludge depends on how much fly ash is generated by the boiler and whether any other particulate control device is upstream of the scrubber. In particular, alkaline fly ash scrubbers rely on the entrapment of ash to act as their primary absorbent, and therefore their sludge contains large amounts of ash. The collection of fly ash and wastes in a spray-drying system occurs simultaneously by a baghouse; therefore, the wastes from these systems also contain large proportions of ash. Recovery FGD systems often require prescrubbers to remove fly ash. Although recovery systems produce only about half the wastes of non-recovery systems, these wastes are predominantly made up of ash.

Specific characteristics of the coal can have a large effect on the quantity of sludge generated. For example, the higher the sulfur content, the more reagent that must be used to achieve a certain level of sulfur dioxide removal and, consequently, the more spent reagent in the sludge. The ash content of the coal affects the amount of ash caught up in the sludge. Just as using low-sulfur coal will reduce the amount of spent reagent, reducing the ash content prior to combustion will greatly reduce the amount of fly ash that is absorbed by wet scrubbers and thus the amount of sludge that must be disposed.

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The amount by which a power plant must reduce sulfur dioxide emissions also affects the volume of sludge produced. To achieve a higher reduction, the amount of reagent used in the scrubber needs to be increased, which will, in turn, produce greater quantities of sludge.

3.2.2.3 Physical Characteristics of FGD Sludge

In general, the same physical properties important in determining the disposal behavior of ash are also important determinants of the disposal characteristics of FGD sludge. These physical characteristics -- particle size, compaction behavior, permeability, and shear strength -- vary considerably depending on the type of scrubber system and what (if any) preparation is done prior to disposal. Exhibit 3-15 presents representative ranges of values for these characteristics of FGD sludge.

Depending on the type of FGD system used, the particle size distribution of FGD sludge can vary substantially. For example, sludge from wet scrubbers tends to have a narrow range of particle sizes. The particles produced by dual-alkali systems are finer than those produced by direct lime or limestone scrubbers, while dry scrubbers generally produce sludge containing larger particles.

The density of FGD sludge depends directly on the method of handling. Wet sludge mixed with ash will have a higher density than untreated sludge, while chemical fixation increases the density even more.²² The density of the particles in dry sludge varies widely.

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EXHIBIT 3-15

REPRESENTATIVE RANGES OF VALUES FOR THE
PHYSICAL CHARACTERISTICS OF FGD SLUDGE

	<u>Wet</u>	<u>Dry</u>
Particle Size (mm)	.001-.05	.002-.074
Density (g/cm3)	0.9-1.7	Variable
Optimum Moisture Content (%)	16-43	0
Permeability (cm/sec)	10^{-6} - 10^{-4}	10^{-7} - 10^{-6}
Unconfined Compressive Strength (psi)	0-1600	41-2250

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-8 - 4-15.

3-37

The solids content of scrubber sludge is a function of many things, including whether the sludge is treated prior to disposal, the size of the particles in the sludge, the sulfur content of the coal, the amount of ash present in the sludge, and the desulfurization process used. The percentage of solids in untreated sludges usually ranges from 20 to 40 percent, although it can be as high as 60 percent.²³ Depending on the method of treatment used before disposal (if any), the percentage of solids could be much higher. In fact, some chemical fixation processes are designed to transform the sludge into a cement-like product.

The permeabilities of untreated FGD sludges from wet scrubber systems generally are very similar. Mixing the sludge with fly ash does not necessarily change the degree of permeability, although if fly ash acts as a fixative when added to the sludge, the mixed waste product will have a reduced permeability. Chemical fixation also can decrease permeability. Sludge from dry scrubber systems has low permeability relative to sludge from wet systems.

The shear strength of FGD sludge is referred to as "unconfined compressive strength," which reflects the load-bearing capacity of the sludge. The unconfined compressive strength of sludge is sensitive to the moisture content and age of the sludge. Untreated wet sludge has no compressive strength and is similar to toothpaste in this respect. Mixing with ash or lime increases compressive strength, as does chemical fixation. Also, as the treated sludge ages, its compressive strength becomes greater.

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3.2.2.4 Chemical Characteristics of FGD Sludge

The major constituents found in wet FGD sludge are determined by the absorbent reagent used, the quantity of fly ash present, the sulfur content of the coal, and whether or not forced oxidation is used.

Most wet FGD systems operate by causing the sulfur dioxide in the flue gas to react with an absorbent reagent, such as lime or limestone, to form a calcium compound, such as calcium sulfite (CaSO_3), calcium sulfate or gypsum (CaSO_4), or calcium sulfite-sulfate ($\text{CaSO}_3 \cdot \text{CaSO}_4$), which can then be removed from the system in the sludge. The ratio of calcium sulfate to calcium sulfite is generally greater in sludge generated by direct limestone scrubber systems than in that produced by direct lime systems.

Dual-alkali scrubber systems differ slightly in that they use absorbent solutions containing sodium hydroxide (NaOH) or sodium sulfite (Na_2SO_3) as well as lime; sludges from these processes tend to have high levels of calcium sulfite and sodium salts. Because these compounds are highly soluble and apt to leach, they may pose problems as major components in a landfilled sludge.²⁴

Spray-drying scrubber systems produce particulates containing either sodium sulfate (Na_2SO_4) and sodium sulfite (Na_2SO_3) or calcium sulfate (CaSO_4) and calcium sulfite (CaSO_3), depending on whether the reagents are sodium- or calcium-based.

Exhibits 3-16 and 3-17 show the major chemical constituents found in sludge solids and sludge liquors. Oxides of calcium, silicon, magnesium, aluminum, iron, sodium, and potassium can be found in most FGD sludge. The presence of

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EXHIBIT 3-16

**CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS
OF WET FGD SLUDGE SOLIDS BY SCRUBBER SYSTEM
AND SOURCE OF COAL ***
(percent of total)

	<u>Direct Lime</u>		<u>Direct Limestone</u>		<u>Dual-Alkali</u>		<u>Alkaline</u>
	<u>East</u>	<u>West</u>	<u>East</u>	<u>West</u>	<u>East</u>	<u>West</u>	<u>Fly Ash</u> <u>West</u>
Calcium Sulfate (CaSO ₄)	15-19	17-95	5-23	85	15-68	82	20
CaSO ₃ ·1/2 H ₂ O	13-69	2-11	17-50	8	13-68	1	15
Calcium Sulfite (CaSO ₃)	1-22	0-3	15-74	6	8-10	11	--
Sodium Sulfate (Na ₂ SO ₄ ·7H ₂ O)	--	--	--	--	4-7	4	--
Fly Ash	16-60	3-59	1-45	3	0-7	8	65

* Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., Bureau of Mine (BOM) Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 4-18.

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EXHIBIT 3-17

CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS
OF WET FGD SLUDGE LIQUORS BY SCRUBBER SYSTEM
AND SOURCE OF COAL a/

Constituent b/	<u>Direct Lime</u>	<u>Direct Limestone</u>		<u>Dual-Alkali</u>
	<u>East</u>	<u>East</u>	<u>West</u>	<u>East</u>
pH (units)	8-9.4	5.5-8.4	6.6-6.8	12.1
Total Dissolved Solids	2,800 - 10,260	5400	3300-14,000	155,700
Chloride	1050-4900	1000	620-4200	4900-5600
Potassium	11-28	24	8-28	320-380
Sodium	36-137	12	370-2250	53,600-55,300
Calcium	660-2520	1600	390-770	7-12
Magnesium	24-420	53	3-9	0.1
Sulfate	800-4500	2500	1360-4000	80,000-84,000
Sulfite	0.9-2.7	160	1-3900	--

a/ Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., BOM Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

b/ All constituent concentrations, unless noted, in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-20.

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these compounds results from the presence of fly ash in the sludge, and they are unreactive in FGD systems. In wet scrubbers that also serve as fly ash collection devices, more than 50 percent of the sludge solids may be ash. However, when an ESP or baghouse precedes the scrubber, ash may make up less than 10 percent of the sludge solids.²⁵

The calcium sulfate/calcium sulfite ratio of the sludge solids is important because sludge containing a greater proportion of sulfates has better disposal properties due to its lower solubility. This ratio is usually higher in systems scrubbing lower sulfur coals and in direct limestone systems. Many scrubber systems add a forced oxidation step to lower the calcium sulfite content of the sludge, thereby lowering its solubility.

The concentration of trace elements in FGD sludge reflects the levels of trace elements in the ash, the efficiency of the scrubber in capturing trace elements in the flue gas, and the trace elements present in the reagent and in the process makeup waters. Fly ash is the primary source of most of the trace elements found in scrubber sludge. Some elements, such as mercury and selenium, may be scrubbed directly from the flue gases and then captured in the scrubber sludge. Exhibit 3-18 illustrates the concentrations at which major trace elements are found in sludge from wet scrubber systems.

3.3 LOW-VOLUME WASTES

Low-volume utility wastes are those waste streams generated in the routine cleaning of plant equipment and in purifying of water used in the combustion process. The types and volumes of low-volume wastes vary among different power

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EXHIBIT 3-18

CONCENTRATION OF TRACE ELEMENTS FOUND IN WET-FGD SLUDGES
(Solids and Liquors)

	<u>Sludge Solids</u> a/			<u>Sludge Liquors</u> b/		
	<u>Range</u>		<u>Median</u>	<u>Range</u>		<u>Median</u>
	<u>Low</u>	<u>High</u>		<u>Low</u>	<u>High</u>	
Arsenic	0.8	52.0	12	0.0004	0.1	0.03
Boron	42.0	530.0	14.0	2.1	76.0	14.9
Cadmium	0.1	25.0	10.6	0.002	0.1	0.02
Chromium	1.6	180.0	15.0	0.0002	0.3	0.02
Copper	6.0	340.0	17.5	0.0045	0.5	0.03
Fluoride	266.0	1017.0	625.0	0.2	63.0	2.3
Mercury	0.01	6.0	0.4	0.00006	0.1	0.005
Lead	0.2	290.0	2.4	0.005	0.5	0.03
Selenium	2.0	60.0	5.0	0.003	1.9	0.18

a/ Sludge solid concentrations in milligrams per kilogram.

b/ Sludge liquor concentrations in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-24.

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plants, depending on plant-specific factors such as the size of the plant, the type of equipment, and the age of the equipment. Some low-volume wastes commonly produced are:

- boiler blowdown,
- coal pile runoff,
- cooling tower blowdown,
- demineralizer regenerants and rinses,
- metal and boiler cleaning wastes,
- pyrites, and
- sump effluents.

Estimates of the total amount of low-volume wastes generated each year by coal-fired power plants are not available. The frequency of generation and the quantities generated vary widely from power plant to power plant, depending on the maintenance requirements of the plant and operating conditions. Variations also occur within the same power plant, according to its maintenance schedule and operations. Exhibit 3-19 gives representative annual production figures for low-volume wastes generated by a typical power plant.

This section presents for each type of low-volume waste a brief description of how the waste is generated, typical quantities produced, and the physical and chemical composition of the waste.

3.3.1 Boiler Blowdown

Boiler systems can be either a once-through (supercritical) type or a

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EXHIBIT 3-19

ANNUAL LOW-VOLUME WASTE GENERATION
AT A REPRESENTATIVE COAL-FIRED POWER PLANT *

<u>Type of Waste</u>	<u>Average Annual Production</u>
Boiler Blowdown	11 million gallons/year
Coal Pile Runoff	20 inches/year
Cooling Tower Blowdown	2.6 billion gallons/year
Demineralizer Regenerant	5 million gallons/year
Gas-side Boiler Cleaning	700,000 gallons/year
Water-Side Boiler Cleaning	180,000 gallons/year
Pyrites	65,000 tons/year

* Assuming a 500 megawatt power plant, operating at 70 percent capacity.

Sources: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979; Volume II: Water Management, EPA-600/7-80-012b, March 1980.

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drum-type. In drum-type boiler systems, after steam passes through the turbines, it is converted back to water in the condenser and is recirculated through the boiler to produce steam again. In this process, impurities that become concentrated in the feedwater periodically must be purged from the system. This waste stream is known as boiler blowdown. A once-through system, however, maintains pressurized steam throughout the cycle, and thus does not require the recirculation of water. These boiler types, therefore, do not generate boiler blowdown.

Boiler blowdown is produced either in a continuous stream or intermittently during the day. The flow is adjusted in order to maintain the desired water quality in the boiler and is dependent on the quality of the feedwater and the size and condition of the boiler. The average blowdown rate for a 500 megawatt unit can range from 20 to 60 gallons per minute, or about 2 to 7 gallons per megawatt-hour.²⁶

Boiler blowdown is generally fairly alkaline with a low level of total dissolved solids. The waste stream usually contains certain chemical additives used to control scale and corrosion. Trace elements commonly found in boiler blowdown are copper, iron, and nickel. The components and characteristics of boiler blowdown are presented in Exhibit 3-20.

3.3.2 Coal Pile Runoff

Power plants typically maintain two types of coal storage piles in their coal yards: an active pile to supply their immediate needs and an inactive or long-term pile, which generally stores a 60- to 90-day supply of coal. Coal

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EXHIBIT 3-20

CHARACTERISTICS OF BOILER BLOWDOWN

Parameter	a/ Range	
	Low	High
pH (units)	8.3	12.0
Total Solids	125.0	1,407.0
Total Suspended Solids	2.7	31.0
Total Dissolved Solids	11.0	1,405.0
BOD5	10.8	11.7
COD	2.0	157.0
Hydroxide Alkalinity	10.0	100.0
Oil and Grease	1.0	14.8
Phosphate (total)	1.5	50.0
Ammonia	0.0	2.0
Cyanide (total)	0.005	0.014
Chromium (total)	0.02	b/
Chromium (Hexavalent)	0.005	0.009
Copper	0.02	0.2
Iron	0.03	1.4
Nickel	0.03	b/
Zinc	0.01	0.05

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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piles are usually 25-40 feet high and can cover an area of up to 75 acres, depending on the size and demands of the power plant.²⁷ Inactive coal piles are generally sealed with a tar spray to protect the coal against the weather; active piles are usually open and exposed. Coal pile runoff is formed when water comes into contact with the piles, whether from rainfall or snowfall, during spraying for dust control, or from underground streams that surface under the piles.

The quantity of coal pile runoff depends primarily on rainfall and, to a lesser extent, the permeability of the soil. It has been estimated that, on average, 73 percent of the total rainfall on coal piles becomes coal pile runoff.²⁸

The composition of coal pile runoff is influenced by the composition of the coal, the drainage patterns of the coal pile, and the amount of water that has seeped through. Bituminous coals generate runoff that is usually acidic, with the level of acidity depending on the availability of neutralizing materials in the coal, while subbituminous coals tend to produce neutral to alkaline runoff. Elements commonly found in high concentrations in coal pile runoff are copper, zinc, magnesium, aluminum, chloride, iron, sodium, and sulfate. Exhibit 3-21 displays ranges of concentrations for these and other characteristics.

3.3.3 Cooling Tower Blowdown

Power plants need cooling systems to dissipate the heat energy that remains after the production of electricity.²⁹ The two major types of cooling systems are once-through and recirculating. Cooling tower blowdown generally refers to

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EXHIBIT 3-21

CHARACTERISTICS OF COAL PILE RUNOFF

Parameter	a/ Range	
	Low	High
pH (units)	2.1	9.3 b/
Acidity (as CaCO ₃)	300.0	7,100.0
Total Dissolved Solids	270.0	28,970.0
Total Suspended Solids	8.0	2,500.0
Aluminum	20.0	1,200.0
Ammonia	0.0	1.8
Arsenic	0.005	0.6
Beryllium	0.01	0.07
Cadmium	0.001	0.003
Chloride	3.6	481.0
Chromium	0.005	16.0
Cobalt	0.025	--
Copper	0.01	6.1
Iron	0.1	5,250.0
Magnesium	0.0	174.0
Manganese	0.9	180.0
Mercury	0.0002	0.007
Nickel	0.1	4.5
Nitrate	0.3	1.9
Phosphorus	0.2	1.2
Selenium	0.001	0.03
Sodium	160.0	1,260.0
Sulfate	130.0	20,000.0
Zinc	0.006	26.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All information, unless noted otherwise, is from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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the water withdrawn from a recirculating cooling system to control the concentration of impurities in the cooling water; although once-through systems also discharge water from the cooling system, this discharge is not typically referred to as cooling tower blowdown. At present, about two-thirds of electric utility power plants use a once-through cooling system. This percentage may decrease, however, due to concern over water availability and potential environmental concern over thermal discharges; consequently, future plants may be built with recirculating systems that use cooling towers or cooling ponds.³⁰

Once-through cooling systems are primarily used by power plants located next to large bodies of water. After passing through the condenser, the cooling water is discharged, usually into a river, lake, or pond. The quantity discharged ranges from 26,000 to 93,000 gallons per megawatt-hour. For a 500 megawatt plant, this roughly equals 70-300 billion gallons per year.³¹ In most instances, the chemical composition of the water remains the same after passing through the condenser, but some changes may occur as the result of the formation of corrosion products or the addition of biocides.

Recirculating cooling systems can use either cooling ponds or cooling towers. In a cooling pond system, water is drawn from a large body of water, such as a pond or canal. After it passes through the condenser to absorb waste heat, the water is recycled back into the pond or canal. Cooling tower systems operate by spraying the water through a cooling tower. About 80 percent of the waste heat contained in the water is then released through evaporation. The remainder of the water is recycled back through the cooling tower system. Cooling tower blowdown is a waste stream bled off to control the concentrations

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of impurities and contaminants in the cooling system that could lead to scale formation in the condenser.³²

The cooling tower blowdown rate is adjusted to maintain water quality in the recirculating cooling system in order to prevent scale formation in the condenser. The quantity of blowdown generated is a function of the quality of the makeup water (the water added to the system to replace that which is lost by evaporation and blowdown), the condition of the cooling system, and the amount of water evaporated by the cooling tower. For a representative 500 megawatt unit, the blowdown rate varies between 2 and 30 cubic feet (15 to 225 gallons) per second.³³

The composition and quantity of cooling tower blowdown varies greatly from plant to plant. It generally reflects the characteristics of the makeup waters (e.g., fresh water versus brackish or saline water) and the chemicals added to prevent the growth of fungi, algae, and bacteria in the cooling towers and to prevent corrosion in the condensers. Some of these chemical additives are chlorine, chromate, zinc, phosphate, and silicate. Ranges of concentration for some of the characteristics and components of cooling tower blowdown are shown in Exhibit 3-22.

3.3.4 Demineralizer Regenerant and Rinses

A power plant must treat water prior to its use as makeup water. The use of demineralizers is the most common method of purification. During the demineralization process, which may entail several rinses, high-purity process water is provided for the boiler through an ion exchange process. The wastes

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EXHIBIT 3-22

CHARACTERISTICS OF COOLING TOWER BLOWDOWN

Parameter	a/ Range	
	Low	High
Alkalinity (as CaCO ₃)	8.0	556.0
BOD	--	94.0
COD	--	436.0
Total Solids	750.0	32,678.0
Total Dissolved Solids	4.1	32,676.0
Total Suspended Solids	0.2	220.0
Ammonia (as N)	0.01	11.6
Nitrate (as N)	0.1	711.0
Phosphorus (as P)	0.1	17.7
Total Hardness (as CaCO ₃)	84.0	2,580.0
Sulfate	7.2	20,658.0
Chloride	5.0	16,300.0
Fluoride b/	0.3	33.0
Aluminum b/	1,100.0	1,700.0
Boron b/	0.5	1.0
Chromium (ug/l)	0.02	120.0
Copper (ug/l)	0.01	1,740.0
Iron (ug/l)	0.1	1,160.0
Lead (ug/l) b/	4.0	--
Magnesium (ug/l)	0.1	1,580.0
Manganese (ug/l) b/	24.0	220.0
Mercury (ug/l) b/	1.5	--
Nickel (ug/l)	0.03	150.0
Zinc (ug/l)	0.02	3,000.0
Oil & Grease	1.0	7.4
Phenols (ug/l)	--	72.0
Surfactants	0.2	--
Sodium	3.4	11,578.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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produced in this process can be either acidic or alkaline. When sulfuric acid is employed as the regenerant, calcium sulfate is precipitated in the waste stream. Exhibit 3-23 presents ranges for the components of demineralizer regenerants and rinses.

Regeneration of boiler makeup water by demineralizers is done on a batch basis. The frequency with which the process occurs depends on the quality of the incoming water, although for a 500 megawatt unit, regeneration usually occurs every one to four days. A single regeneration requires approximately 30,000 gallons of water, which amounts to about 3-10 million gallons per year.³⁴

3.3.5 Metal and Boiler Cleaning Wastes

This category of low-volume waste streams can be divided into two basic types: gas-side cleaning wastes and water-side cleaning wastes. Gas-side wastes are produced during maintenance of the gas-side of the boiler, which includes the air preheater, economizer, superheater, stack, and ancillary equipment. Residues from coal combustion (such as soot and fly ash), which build up on these surfaces, must be removed periodically -- usually with plain water containing no chemical additives.

Water-side wastes are produced during cleaning of the boiler tubes, the superheater, and the condenser, which are located on the water-side or steam-side of the boiler. The scale and corrosion products that build up on these boiler parts must be removed with cleaning solutions containing chemical additives.

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EXHIBIT 3-23

CHARACTERISTICS OF
SPENT DEMINERALIZER REGENERANTS

Parameter	a/ Range	
	Low	High
Alkalinity (as CaCO ₃)	0.0	3,831.0
BOD	0.0	344.0
COD	0.0	440.0
Total Solids	284.0	36,237.0
Total Dissolved Solids	283.0	25,235.0
Total Suspended Solids	0.0	300.0 c/
Ammonia (as N)	0.0	435.0
Phosphorus (as P)	0.0	87.2
Turbidity (JTU)	2.5	100.0
Total Hardness (as CaCO ₃)	0.0	8,000.0
Sulfate	4.5	9,947.0
Chloride	0.0	20,500.0
Boron	0.0	0.1
Chromium	0.0	2,168.0
Copper (ug/l)	0.0	3,091.0
Iron (ug/l)	0.0	2,250.0
Lead (ug/l) b/	160.0	37,500.0
Magnesium (ug/l)	0.0	753.0
Manganese (ug/l)	0.0	3,100.0
Mercury (ug/l)	0.05	--
Nickel (ug/l)	0.0	560.0
Zinc (ug/l)	0.0	4,500.0
Oil & Grease b/	0.0	24.5
Phenols (ug/l)	0.0	303,000.0
Surfactants b/	1.7	--
Nitrate as N	0.0	118.0
Algicides b/	0.003	--
Sodium	4.9	30,000.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these components were limited.

c/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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The boiler and auxiliary equipment are cleaned intermittently, creating large quantities of wastes in a short time. Gas-side boiler cleaning is done approximately twice a year. The volume of the waste stream produced depends on the size of the boiler and the number of rinses. For a typical plant, gas-side cleanings can produce between 24,000 and 700,000 gallons of wastes. Water-side equipment is cleaned less frequently, approximately once every three years. As is true of gas-side cleaning, the volume of waste produced varies with the number of rinses. A representative 500 megawatt unit generates about 120,000-240,000 gallons of wastewater per treatment.³⁵

Because no chemicals are used, the composition of the waste streams associated with gas-side cleaning directly reflects the composition of the soot and fly ash residues and, therefore, of the coal that is burned. Exhibit 3-24 shows two reported values for components and characteristics of gas-side cleaning waste streams.

The particular solution used for the cleaning of the water-side of the boiler varies depending on the equipment being cleaned and the type of scale that needs to be removed. When the scale contains high levels of metallic copper, an alkaline solution that contains ammonium salts, an oxidizing agent such as potassium or sodium bromate or chlorate, and nitrates or nitrites is used. Exhibit 3-25 presents some of the major characteristics associated with these types of solutions and representative ranges of concentrations in which they are found.

For the removal of scale caused by water hardness, iron oxides, and copper oxide, an acid cleaning solution is needed. Usually hydrochloric acid acts as

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EXHIBIT 3-24

REPORTED CHARACTERISTICS OF GAS-SIDE CLEANING WASTES

<u>Parameter</u>	<u>Quantities Produced per Cleaning</u> <u>(in lbs. except as noted) a/</u>	
	<u>Source A</u>	<u>Source B</u>
Cleaning Frequency (cycles/yr)	2.0	8.0
Batch Volume (1000 gallons)	720.0	24.0
Alkalinity	0.0	6.0
COD	1,134.0	19.0
Total Solids	40,861.0	4,002.0
Total Dissolved Solids	35,127.0	3,002.0
Total Suspended Solids	3,823.0	119.1
Turbidity (JTU)	476.0	98.0
Hardness	35,409.0	791.4
Ammonia	1.5	0.4
Chloride	0.0	18.0
Chromium (total)	0.03	1.0
Copper	--	0.3
Iron	900.0	30.0
Lead	--	--
Magnesium	11,949.0	190.3
Nickel	30.0	--
Nitrate	14.7	0.7
Phosphorus	11.1	0.3
Sodium	0.0	9.0
Sulfate	11,949.0	299.4
Vanadium	--	--
Zinc	28.7	2.0

a/ Quantities produced are shown for two different reported values.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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EXHIBIT 3-25

CHARACTERISTICS OF SPENT WATER-SIDE
ALKALINE CLEANING WASTES

Parameter	Range ^{a/}	
	Low	High
Alkalinity (as CaCO ₃)	20,200.0	25,700.0
NH ₃ -N	4,280.0	6,360.0
Kjeldahl-N	5,190.0	7,850.0
Nitrate-N	1.0	193.0
Oil & Grease	7.9	10.3
BOD ₅	5,820.0	8,060.0
COD	14,600.0	20,900.0
Total Suspended Solids	5,580.0	6,720.0
Total Dissolved Solids	10.0	400.0
TDS	22,100.0	32,300.0
Total Iron	180.0	10,800.0
Silica	1.0	40.0
Chromium	0.2	7.7 ^{b/}
Copper	8.0	1,912.0
Lead	0.004 ^{b/}	23.0 ^{b/}
Manganese	0.1	14.3
Nickel	2.5	130.0
Tin	2.0	20.7
Zinc	3.1	390.0
pH (units)	8.4 ^{b/}	10.3 ^{b/}

^{a/} All concentrations, unless noted, in milligrams per liter.

^{b/} Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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the solvent in these solutions, although sulfuric, phosphoric, and nitric acids can also be used. Organic acids have been used increasingly as substitutes for hydrochloric acid because of their lower toxicity. For the removal of silica deposits, hydrofluoric acid or fluoride salts are added to the cleaning solution. Exhibit 3-26 presents the various characteristics of acid boiler cleaning solutions.

Alkaline chelating rinses and alkaline passivating rinses are often used to remove iron and copper compounds and silica and to neutralize any residual acidity left over from acid cleaning. These solutions may contain phosphates, chromates, nitrates, nitrites, ammonia, EDTA, citrates, gluconates, caustic soda, or soda ash. Exhibit 3-27 gives representative ranges for these components and others present in these rinses.

3.3.6 Pyrites

Pyrites are the solid mineral compounds, such as iron sulfides or other rock-like substances, present in raw coal. Most pyrites are generally separated out before coal is burned, usually at a preparation plant prior to shipment to the power plant. Smaller quantities of pyrites are often removed at the power plant just before the coal is pulverized. The size of the deposits depends on the method by which they are separated from the coal.

The volume of pyrites collected at a power plant depends on the amount and quality of the coal that is burned, which is determined by the source of the coal and the preparation process, as well as by the coal pulverization process.

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EXHIBIT 3-26

CHARACTERISTICS OF SPENT WATER-SIDE
HYDROCHLORIC ACID CLEANING WASTES

Parameter	Range ^{a/}	
	Low	High
pH (units)	0.5	3.3
Total Suspended Solids	8.0	2375.0
Silica	19.0	280.0
NH3-N	80.0	325.0
Nitrogen	1.0	870.0
Phosphorus	1.0	300.0
Sulfate	1.0	10.0
Aluminum	6.5	8.2
Arsenic	0.01	0.1
Barium	0.1	0.4
Beryllium	0.0	0.1
Cadmium	0.001	0.13 ^{b/}
Calcium	16.0	980.0
Chromium	0.005	16.8
Copper	2.2	960.0
Iron	1125.0	6470.0
Lead	0.01	5.2
Magnesium	5.7	8.8
Manganese	6.9	29.0
Mercury	0.0	0.002
Nickel	3.0	500.0
Potassium	1.4	2.3
Selenium	0.002	0.004
Silver	0.02	0.2 ^{b/}
Sodium	9.2	74.0
Tin	1.0	7.3
Zinc	0.9	840.0

^{a/} All concentrations, unless noted, in milligrams per liter.

^{b/} Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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EXHIBIT 3-27

CHARACTERISTICS OF SPENT WATER-SIDE
ALKALINE PASSIVATING WASTES

<u>Parameter</u>	<u>Range*</u>	
	<u>Low</u>	<u>High</u>
pH (units)	9.2	10.0
Total Suspended Solids	13.0	45.0
NH3-N	15.0	232.0
Kjeldahl-N	97.0	351.0
Nitrite-N	7.0	12.9
BOD5	40.0	127.0
COD	98.0	543.0
TOC	16.0	23.0
Iron	7.5	28.0
Chromium	0.0	0.4
Copper	0.1	1.2

* All concentrations, unless noted, in milligrams per liter.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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The amount of pyrites to be disposed at a power plant can vary considerably, although coal typically contains up to 5 percent pyrites.³⁶ A 500 megawatt plant, depending on how often it operates and the quality of its coal, will generate, on average, between 30,000 and 100,000 tons of pyrites per year. The characteristics of pyrites and pyrite slurry transport water are shown in Exhibit 3-28.

3.3.7 Sump Effluents

Floor and yard drains collect waste streams from a variety of sources at power plants, such as rainfall, seepage from ground-water sources, leakage, small equipment cleaning operations, and process spills and leaks. As a result, the composition of drain effluents is highly variable. Depending on the particular circumstances at the power plant, these waste streams may contain coal dust, fly ash, oil, and detergents.

The frequency of sump effluent generation and quantities generated are very plant-specific. The more efficient a plant's operating procedures, the smaller this waste stream will be. Also, power plants located in dry areas of the country will have relatively small amounts of wastes collected in yard drains.

3.4 SUMMARY

In the process of generating electricity, coal-fired utility power plants produce a number of waste products. These wastes are produced in large quantities and have widely varying physical and chemical characteristics.

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EXHIBIT 3-28

CHARACTERISTICS OF PYRITES AND
PYRITE TRANSPORT WATER

<u>Parameter</u>	<u>Pyrite Slurry Water</u> ^{a/}	<u>Pyrites</u> ^{b/} <u>Solid Form</u>
Total Suspended Solids	1,700.0	--
Total Aluminum	93.3	--
Total Calcium	134.0	--
Total Iron	220.0	--
Total Magnesium	13.6	--
Sulfate	177.0	--
pH (units)	7.7	--
Arsenic	--	500-5000
Chromium	0.1	--
Copper	0.1	10-10,000
Lead	0.1	200-1000
Zinc	0.3	500-10,000
Manganese	--	10-5000
Selenium	--	10-100
Silica	212.0	--
Silver	--	10-50
Cobalt	--	100-5000
Nickel	--	10-1000
Vanadium	--	100-200

a/ All concentrations, unless noted, in milligrams per liter.

b/ All concentrations in parts per million.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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- Coal-fired electric utility power plants produce three major forms of wastes:
 - 1) Ash, formed from the noncombustible material present in coal. There are three types of ash -- fly ash, bottom ash, and boiler slag;
 - 2) FGD sludge, produced by flue gas desulfurization systems designed to remove sulfur oxides from flue gas; and
 - 3) Low-volume wastes, generated primarily from equipment maintenance and cleaning operations.
- In 1984, about 69 million tons of ash and about 16 million tons of FGD sludge were produced by coal-fired electric utilities. By the year 2000, these wastes are expected to increase to about 120 million and 50 million tons, respectively.
- Several physical characteristics of utility waste determine the waste's behavior during disposal and the potential for leachate problems. These characteristics vary a great deal among the different types of ash and FGD sludge.
- The chemical constituents of ash and FGD sludge largely depend on the chemical components in the coal. Other chemical compounds present in FGD sludge, primarily calcium and sodium salts, are the result of the reactions between the absorbent reagent used and the sulfur oxides in the flue gas.
- Compared with ash and FGD sludge, low-volume wastes are generally produced in much smaller quantities. Many of these wastes contain various chemicals from the cleaning solutions used for power plant operations and maintenance; potentially-hazardous elements in these chemicals may be found at high concentrations in the low-volume waste.

CHAPTER THREE

NOTES

¹ See Appendix B for a more in-depth discussion of boiler types and how the type of boiler affects the types of waste that are generated.

² Babcock & Wilcox, Steam: Its Generation and Use, New York: The Babcock & Wilcox Company, 1978, p. 18-3.

³ Ibid.

⁴ Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants-1985, DOE/EIA-0191(85), July 1986.

⁵ ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Pound Sulfur Dioxide Emission Reduction Cases, prepared for EPA, February 1986. There are many factors that can affect the amount of coal consumed, including electricity growth rates, oil and gas prices, types of technology available, etc. Nevertheless, utilities will continue to burn substantial amounts of coal in the foreseeable future.

⁶ Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 45.

⁷ There are presently over 500 coal cleaning plants in the U.S., the majority of which are operated by coal companies and located at the mouth of the mine. The type of cleaning method employed depends upon the size of the coal pieces to be cleaned, a factor that can be controlled at the cleaning plant.

The most widely used methods of coal cleaning are those that use specific gravity, relying on the principle that heavier particles (i.e., impurities) separate from lighter ones (i.e., coal) when settling in fluid. A common method of cleaning coarse coal pieces is to pulse currents of water through a bed of coal in a jig; impurities, such as shale and pyrite, sink, while the coal floats on top. The heavy, or dense, media process is used for cleaning coarse and intermediate-sized pieces. A mixture of water and ground magnetite, having a specific gravity between that of coal and its impurities, acts as a separating fluid. An inclined vibrating platform with diagonal grooves, known as a concentrating table, also is used to clean intermediate-sized coal pieces. Raw coal slurry is fed onto the high end of the table. As the slurry flows down, the vibrations separate the coal from the refuse, allowing the lighter coal to be carried along in the water, while the heavier impurities are trapped in the grooves.

Because of their small size, fine coal particles are very difficult to clean. Their recovery is important, however, because these particles can provide up to 25 percent of the energy derived from raw coal. A popular method of fine coal cleaning is froth flotation. The coal pieces are coated with oil and then agitated in a controlled mixture of water, air, and reagents until froth is formed on the surface. Bubbles tend to attach to the coal pieces, keeping them buoyant, while heavier particles such as pyrite, shale, and slate remain dispersed in the water. The coal can then be removed from the

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surface. For more information, see Coal Preparation, 4th edition, Joseph Leonard, editor, American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., 1979.

8 Ash melts when heated to a sufficiently high temperature. The temperatures at which the ash changes forms -- e.g., melting from a cone shape to a spherical shape to a hemispherical shape to a flat layer -- are referred to as ash fusion temperatures.

9 Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 3-4. A micron is 0.001 millimeters.

10 Ibid.

11 The compressibility of a material is measured as the ratio of its height at 50 psi to its original height at atmospheric pressure. The dry density, the ratio of weight to unit volume of the material containing no water, affects permeability and strength, which in turn determine the structural stability of a landfill and the extent of leachate mobility. The optimum moisture content is the moisture content, in percentage terms, at which the material attains its maximum density.

12 In 1979 the New Source Performance Standards, part of the Clean Air Act of 1971, were revised. The new regulations required that all coal-fired electric utility units with capacity greater than 73 megawatts, whose construction commenced after September 18, 1978, would not only have to meet a 1.2 pound sulfur dioxide per million Btu emission limit, but would have to do so by a continuous system of emissions reduction. New power plants must reduce sulfur dioxide emissions between 70 and 90 percent, depending on the type of coal burned.

13 During fluidized bed combustion the sulfur oxides react with limestone or dolomite to form calcium sulfate. In LIMB technology, limestone is injected into the boiler, also forming calcium compounds.

14 Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, p. VII-15.

15 Ibid., p. VII-18.

16 Ibid., p. VII-23.

17 Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 4-4.

18 "Dry Capture of SO₂," EPRI Journal, March 1984, p. 21.

19 Ibid., p. 15.

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²⁰ ICF, op. cit. See Appendix B for a detailed explanation of how future FGD sludge estimates were derived.

²¹ U.S. Environmental Protection Agency, Controlling SO₂ Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Volume I, EPA-600/7-78-044a, March 1978, p. 23.

²² See Chapter Four for a detailed discussion of the methods of sludge fixation.

²³ Michael Baker, Jr., Inc., State-of-the-Art of FGD Sludge Fixation, prepared for Electric Power Research Institute, January 1978, p. 2-25.

²⁴ Tetra Tech, Inc., op. cit., p. 4-17.

²⁵ Ibid.

²⁶ Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 26.

²⁷ U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979: Volume II: Water Management, EPA-600/7-80-012b, March 1980, p. 3-146.

²⁸ Ibid., p. 3-147.

²⁹ Ibid., p. 3-16. About 35 to 40 percent of the total heat input of a power plant is converted to electricity, about 5 percent is lost in the stack gases, and the remaining 55 to 60 percent is rejected in the condenser.

³⁰ Ibid., p. 3-17.

³¹ Ibid.

³² The term "cooling tower blowdown" refers to the waste waters produced by all recirculating cooling systems, whether they use a cooling pond or a cooling tower.

³³ U.S. EPA, Waste and Water Management, p. 3-19.

³⁴ Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 27.

³⁵ Ibid., p. 27.

³⁶ Ibid., p. 28. The term "pyrites" is used to refer to a variety of rock-like substances that may be found in raw coal; it does not just refer to pyritic sulfur that is found in all raw coal, although pyritic sulfur is typically part of the pyrites generated at a power plant.

CHAPTER FOUR

COAL COMBUSTION WASTE MANAGEMENT PRACTICES

Under Section 8002(n) of RCRA, EPA is to analyze "present disposal and utilization practices" and "alternatives to current disposal methods." This chapter addresses these issues by first examining the various state regulations that affect coal combustion disposal since these regulations set the context for current practices. The following section describes coal combustion waste management practices. First, three commonly employed types of land management practices are described in detail. Next, this chapter describes additional measures currently employed by some utilities; more widespread use of these technologies could be employed as an alternative to current practices. Ocean disposal, an alternative that is in the research and development stage, is also addressed in this chapter. Finally, the extent of coal combustion waste recycling as an alternative to disposal is described.

4.1 STATE REGULATION OF COAL COMBUSTION WASTE DISPOSAL

Since coal combustion wastes are currently exempt from Federal hazardous waste regulation under RCRA, their regulation is primarily carried out under the authority of state hazardous and solid waste laws. State solid waste laws establish programs to provide for the safe management of non-hazardous solid wastes. If solid wastes are considered hazardous, state hazardous waste laws establish programs to provide for their safe management. To implement these laws, state health or environmental protection agencies promulgate solid and hazardous waste regulations. A 1983 report for the Utility Solid Waste Activities Group (USWAG) surveyed these regulations; the USWAG report provided

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summaries of state regulations based on applicable state laws, regulations, and interviews with state environmental officials.¹ EPA updated the information provided in the USWAG summaries for the purposes of this report.

Exhibit 4-1 lists the disposal requirements promulgated under each state's solid waste (non-hazardous) regulations. (As will be discussed below, it is very rare for coal combustion wastes to be regulated as hazardous under state regulations.) The list of states is arranged in descending order according to each state's share of national coal-fired generating capacity (Column 1 of Exhibit 4-1). The information shown in the Exhibit is discussed in detail in Sections 4.1.1 and 4.1.2.

4.1.1 State Classification of Coal Combustion Wastes

Forty-three states have exempted coal combustion wastes from hazardous waste regulation.² As a result, in these states the state solid waste laws, which apply to non-hazardous wastes, regulate the disposal of these coal combustion wastes. Column 2 of Exhibit 4-1 shows that: (1) in seven states, coal combustion wastes are not exempt from hazardous waste regulation (indicated by an entry of CH), which means that they are tested to determine whether they will be regulated as solid or hazardous wastes; (2) in all but one of the remaining states wastes are regulated by solid waste regulations (indicated by an entry of SW); and (3) in the one remaining state, wastes are exempt from both the hazardous waste and solid waste regulations (indicated by an entry of EX).

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EXHIBIT 4-1
STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
Texas	8.40%	SW	OFF SITE	NO	NO	NO	MAY	YES	YES
Indiana	6.44%	SW	ON & OFF SITE	NO	NO	NO	MAY	NO	NO
Kentucky	6.43%	CH	ON & OFF SITE	YES	MAY	YES	MAY	YES	NO
Ohio	6.02%	EX							
Pennsylvania	5.71%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Illinois	5.46%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	YES
West Virginia	3.87%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
North Carolina	3.41%	SW	ON & OFF SITE	YES	NO	NO	YES	YES	NO
Michigan	3.37%	SW	ON & OFF SITE	YES	NO	NO	YES	NO	NO
Georgia	3.35%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Florida	3.26%	SW	OFF SITE	YES	YES	YES	YES	YES	YES
Missouri	3.16%	SW	ON & OFF SITE	YES	NO	MAY	NO	YES	NO
Alabama	3.08%	SW	ON & OFF SITE	YES	MAY	NO	YES	YES	NO
Tennessee	2.54%	CH	ON & OFF SITE	YES	MAY	NO	MAY	YES	NO
Nevada	2.49%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
South Carolina	2.24%	SW	ON & OFF SITE	YES	NO	YES	NO	YES	NO
Wisconsin	2.19%	SW	ON & OFF SITE	YES	MAY	MAY	MAY	YES	YES
Louisiana	1.98%	SW	ON & OFF SITE	YES	YES	YES	YES	YES	YES
Colorado	1.97%	SW	OFF SITE	YES	YES	YES	YES	NO	NO
Iowa	1.83%	SW	OFF SITE	NO	NO	MAY	NO	NO	NO
Wyoming	1.82%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Kansas	1.69%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Arizona	1.67%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
New Mexico	1.58%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Utah	1.57%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Minnesota	1.54%	SW	ON & OFF SITE	YES	NO	MAY	YES	YES	NO
Arkansas	1.48%	SW	ON & OFF SITE	YES	NO	NO	NO	YES	YES
Maryland	1.48%	SW	OFF SITE	NO	NO	YES	YES	NO	NO
North Dakota	1.39%	SW	ON & OFF SITE	NO	NO	MAY	YES	YES	YES
Oklahoma	1.34%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
New York	1.24%	SW	ON & OFF SITE	YES	MAY	MAY	YES	YES	NO
Virginia	0.94%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Washington	0.93%	CH	OFF SITE	YES	YES	YES	YES	YES	NO
Nebraska	0.85%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO
Montana	0.74%	SW	OFF SITE	YES	NO	NO	NO	NO	NO
Mississippi	0.62%	SW	OFF SITE	NO	MAY	NO	NO	YES	NO
New Jersey	0.51%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
Massachusetts	0.41%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Oregon	0.31%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	YES
Delaware	0.27%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Maine	0.15%	CH	ON & OFF SITE	YES	YES	YES	MAY	YES	NO
South Dakota	0.13%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	NO

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EXHIBIT 4-1 (continued)
STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
New Hampshire	0.12%	SW	ON & OFF SITE	NO	NO	NO	YES	NO	NO
Alaska	0.01%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	NO
California	0.00%	CH	ON & OFF SITE	YES	NO	YES	MAY	YES	YES
Connecticut	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Vermont	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Rhode Island	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	NO	NO
Hawaii	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Idaho	0.00%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO

NOTES

Column (1) Percent national coal-fired capacity: i.e., each state's share of total U.S. coal-fired generating capacity.

Column (2) Classification: SW - coal combustion waste is exempted from hazardous waste regulation and regulated as a solid waste.

CH - coal combustion waste is not exempted from hazardous waste regulation and is tested for hazardous characteristics (In practice, coal combustion wastes are rarely considered hazardous, therefore columns 3-8 reflect solid, not hazardous, waste regulations).

EX - coal combustion waste is exempted from both solid and hazardous waste regulation.

Column (3) Permits: Permits are required for off-site facilities only, or for both on-site and off-site facilities.

Columns (4), (5), (6), (7), (8), (9): YES - the disposal standard is imposed by state regulations.

NO - the disposal standard is not imposed by state regulations.

MAY - the regulation states that a case-by-case investigation will determine whether the disposal standard will be imposed.

Source: Wald, Harkrader & Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, prepared for the Utility Solid Waste Activities Group, September, 1983.

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Of the seven states that do not exempt coal combustion wastes from hazardous waste regulation (indicated by a CH classification in Exhibit 4-1), California burns little coal to produce electricity. The hazardous waste regulations of the six remaining states -- Kentucky, Tennessee, New Jersey, Oklahoma, Maine, and Washington -- regard coal combustion wastes as "characteristic" waste; that is, the wastes are tested for Extraction Procedure (EP) toxicity (see Chapter Five for further discussion), and if the waste proves to be toxic, some or all sections of state hazardous waste regulations apply. In Kentucky, for example, hazardous waste standards concerning lining and leachate control are enforced for coal combustion wastes that are found to be toxic, but utilities are not required to participate in the hazardous waste management fund established to ensure the long-term viability of disposal facilities. Similarly, according to the hazardous waste regulations of Tennessee and Oklahoma, if a waste is determined to be toxic, strict analysis and monitoring requirements must be followed, but compliance with state hazardous waste design and operating standards is not required. Officials from these five states have indicated that it is very rare for a coal-burning utility's waste to be classified as hazardous.³ Therefore, state solid waste regulations, with only isolated exceptions, establish the standards applicable to most coal combustion waste disposal activities.

Although solid waste regulations in most states do not differentiate between coal combustion wastes and other solid wastes, solid waste regulations in three states make specific reference to coal combustion waste disposal:

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- Ohio's solid waste regulations list "non-toxic fly ash ... and slag ... that are not harmful or inimical to public health" as wastes that are exempt from solid waste regulation. Ash is typically determined to be non-toxic, according to the USWAG report.
- Maine's solid waste regulations provide a separate, more stringent set of design and operating requirements for the disposal of coal combustion wastes. The requirements call for lining, leachate control, and ground-water monitoring at coal combustion waste sites. These standards do not apply to other solid waste disposal facilities.⁴
- Pennsylvania has established industry-specific waste disposal standards. Pennsylvania's regulations for coal combustion waste disposal exclude the leachate control systems and liner requirements that apply to general solid waste disposal facilities.

4.1.2 Requirements for Coal Combustion Waste Disposal

The solid waste regulations of every state require that off-site solid waste disposal facilities be permitted or have some form of official approval. In order to obtain a permit, the operator of a facility must meet the requirements that are outlined in the regulations. These regulations are listed in Exhibit 4-1 and described below:

- The regulations in 41 states require permits for both on-site and off-site facilities. Eight states' regulations explicitly exempt on-site disposal from the permit requirement (Ohio, which exempts coal combustion wastes from solid waste regulation, is not included among the eight states). Column 3 of Exhibit 4-1 shows whether a permit is required for the operation of on-site and off-site solid waste disposal facilities.⁵